[UCI]I804:21028-200000005375

공학석사 학위논문

Analysis of CO_2 Transportation System Considering Reservoir Pressure Behavior and Energy Saving Method for CO_2 Injection Process

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2018년 2월

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2017년 12월 28일

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Abstract

Offshore CCS (Carbon Capture & Storage) is an alternative to greenhouse gas reduction technology that stores captured CO_2 in a reservoir or aquifer formed in the offshore underground. In order to inject large amounts of CO_2, a CO_2 transport and injection system is required, which can consist of a subsea pipeline, a riser, a topside injection facility, and an injection well. A detailed analysis of the above system should be performed to economically transport and inject captured CO_2. In this study, transport and injection system was analyzed considering the reservoir pressure behavior during the injection period of about 10 years when the depleted gas field located in the East Sea coast of Korea is used as the CO_2 storage, and suggested the design method of necessary equipment. The analysis also found that phase change control is required at the topside for stable CO_2 injection. Since the conventional process uses only heating, a large amount of energy consumption is inevitable. Therefore, in this study, a new process using seawater heat source and compressor discharge heat source was proposed to reduce the energy required for the conventional process. The proposed new process could reduce the energy consumption by 14 ~ 18% compared to the conventional process. In addition, optimum operating conditions and key parameters of the new process were derived.

KEY WORDS: Offshore CCS; CO_2 Transport & Injection; Topside Process; Phase-Change Control; Energy Consumption.

저류층 압력 거동을 고려한 CO_2 수송시스템 분석과 CO_2 주입공정의 에너지 절약 방법

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Abstract

해양 CCS(Carbon Capture & Storage)는 온실가스 감축을 위한 대안으로 포집된 CO2를 해양 지중에 형성된 저류층이나 대수층에 저장하는 기술이다. 대량의 CO_2를 주입하기 위해서 CO_2 운송 및 주입 시스템이 필요하며, 이는 해저 파이프라인, 라이저, 탑사이드 주입설비, 주입정 등으로 구성될 수 있다. 포집된 CO_2를 경제적으로 운송하고 주입하기 위해 위와 같은 시스템의 상세한 분석이 수행되어야 한다. 본 연구에서는 국내 동해 대륙붕에 위치한 고갈 가스전을 CO_2 저장소로 활용할 경우 약 10년의 주입기간 동안 저류층 압력 거동을 고려하여 전체 시스템을 분석하고 필요한 기자재의 설계 방안을 제시하였다. 또한 분석 결과 안정적인 CO_2 주입을 위해 탑사이드에서 상변환 제어가 필요함을 발견하였다. 기존의 상변환 공정은 가열만을 이용하기 때문에 많은 양의 에너지 소비가 불가피 하였다. 따라서 본 연구에서는 기존 공정에 소요되는 에너지를 감축하기 위해 해수열원과 압축기 배열원을 이용한 새로운 공정을 제안하였고, 제안된 새로운 공정은 기존 공정 대비 14~19 %의 에너지 소모량을 감축할 수 있었다. 더불어 새로운 공정의 최적 작동 조건과 주요 매개 변수를 도출하였다.

KEY WORDS: Offshore CCS 해양 CCS; CO_2 Transport & Injection CO_2 운송 및 주입; Topside Process 탑사이드 공정; Phase-Change Control 상변화 제어; Energy Consumption 에너지 요구량.

Chapter 1 Introduction

1.1 Carbon capture & storage technology

Offshore Carbon Capture and Storage (CCS) is an alternative to greenhouse gas reduction aimed at reducing CO_2 emissions into the atmosphere. It is a technology that collects and transports CO_2 from a large power plant or steel mill and stores it in a offshore aquifer or a depleted reservoir. Many countries are carrying out research and development for the commercialization and demonstration of offshore CCS. The UK has completed FEED (Front End Engineering Design) for Longannet, Kingsnorth, Peterhead and White Rose businesses for CCS(EON UK, 2011; GCCSI, 2015; Gough et al., 2010; Mallon et al., 2013; ScottishPower CCS Consortium, 2011). Norway operates the Sleipner project and the Snøhvit project to carry out a large-scale offshore CCS project that injects 1-2 million tonnes of CO_2 annually into the seabed(Arts et al., 2004; Eiken et al., 2011; GCCSI, 2015). In Australia, commissioning of the Gorgon project is taking place in the western coastal area. The Gorgon CO_2 injection project is the world's largest project to inject 4 Mtpa of CO_2 into deep salt aquifers(GCCSI, 2016; Liu et al., 2015). Japan began CO_2 injection in the Tomakomai CCS project in April 2016. It captures 100,000 tons of CO_2 per year and injects it into the strata near the coast(GCCSI, 2016; Tanaka et al., 2014; Tanase et al., 2013). In December 2015, Petrobras announced that it would inject about 3 million tons of CO_2 into the reservoir, about 20 km from the coast of Rio de Janeiro, in the Santos Basin Pre-Salt oilfield CCS project in Brazil(GCCSI, 2016; Melo et al., 2011). In Korea, a study was conducted to transport, inject and store 1 million tons of CO_2 per year in depleted gas fields located on the continental shelf of the East Sea(Huh et al., 2013, 2009;

Jung et al.,2013; KRISO, 2016; Yoo et al., 2013). In this paper, the CO_2 transport and injection system analysis was performed according to the pressure behavior of the reservoir when the depleted gas field was used as a storage site in the East Sea of Korea. In addition, a new process using a seawater heat source and a compressor discharge heat source has been proposed to reduce the energy required for the injection process.

1.2 The need for CO_2 transport and injection system analysis

A detailed analysis should be performed to economically transport and inject CO_2 into offshore geological storage. It is important to analyze the effects of seasonal environmental changes such as seawater temperature as well as the effect of pressure increase due to CO_2 accumulation in the reservoir during the injection period. In this paper, the behavior of CO_2 in the transport and injection system is analyzed through numerical analysis when the depleted gas field located in the East Sea continental shelf of Korea is used as CO_2 storage.

In the offshore CCS project, accumulation of CO_2 injected and stored into the underground reservoir as the injection period elapses increases the reservoir pressure(Hosseini et al.,2013; KNOC, 2015). 이This increase in reservoir pressure results in changes operating conditions in CO_2 transport and injection facilities such as subsea pipelines, topside process facilities on offhore platform, and injection wellbore. Therefore, an analysis that reflects changes in operating conditions over the period of injection during the basic design and conceptual design stages should be performed in detail. For the Kingsnorth project in the UK, the pressure of the reservoir over the project period ranges from 2.1 to 157.6 bar (E.ON, 2011). On the other hand, the pressure range of the reservoir of depleted gas reservoirs in Korea is 71 ~ 241 bar. This difference in reservoir pressure range results in different operating pressures for transport and storage systems. In particular, due to the reservoir pressure range of this study, the situation occurred operating conditions of around the critical point when transporting and injecting CO_2. The CO_2 of near critical point show rapid physical properties change in the transport and injection system even if small changes in temperature and pressure occur. Therefore, in this study numerical analysis predicted and analyzed the effect of the increase of the reservoir pressure over the project period on the CO_2 behavior in the subsea pipeline, riser, topside and injection wellbore.

1.3 Necessity of energy saving for CO_2 injection process

CCS is carried out through four stages: capture, transport, injection, and storage. Consideration of the state of CO_2 in the system is essential for efficient transport and injection of CO_2. In the case of offshore CCS, especially with subsea pipelines, the phase of CO_2 generally undergoes a dramatic change at the boundary of the transport and injection stages, which is an intermediate stage. CO_2 transported along the subsea pipeline is transported in a liquid phase or supercritical state close to the liquid phase due to the action of the relatively low surrounding seawater temperature. However, the CO_2 injected into the reservoir during the injection process is injected into the gas phase or supercritical state near the gas phase due to the high geothermal heat around the injection wellbore(KRISO, 2016; Min et al., 2016; EON UK, 2011). This state difference between transport and injection systems can cause abnormal flow in the subsea pipeline and in the injection wells. To avoid this problem, a proper injection process is required at the topside of the platform. To do this, the FEED study on the UK Kingsnorth project proposed a CO_2 heating process through multiple heat exchangers at the topside of the offshore platform(EON UK, 2011). However, in order to obtain the enormous amount of heat energy required for this process, a large amount of fuel must be supplied to the offshore platform from the land or an additional facility must be installed. Given the location of offshore platform, the less energy supply required by the platform, the more economical it will be(Nguyen et al., 2016). Therefore, this study proposed a new CO_2 heating process using seawater heat source and compression array source. To verify the effectiveness of the proposed new method, the existing heating method and comparative analysis were performed using Aspen HYSYS V.8.8(Aspentech, 2015).

Chapter 2 Analysis of CO_2 Transport and Injection Systems

2.1 Numerical Analysis Method

2.1.1 Numerical Analysis Model

It is assumed that captured CO_2 is temporarily stored in a terminal near the depleted gas field (KRISO, 2016). The CO_2 at the temporary storage terminal is transported along the seabed pipeline and the riser to the offshore platform near the reservoir. The CO_2 arriving at the topside of the platform is then injected into the reservoir along the injection wellbore. The transport and injection system of this study is shown in Fig.1. in this study, the single component module (Schlumberger, 2014) of the OLGA 2014.1 was used. The CO_2 of this study was assumed to have a purity of more than 99% for ease of numerical calculation and utilized the properties of pure CO_2. The numerical analysis model of the system shown in Fig. 1 is designed as shown in Fig.2.

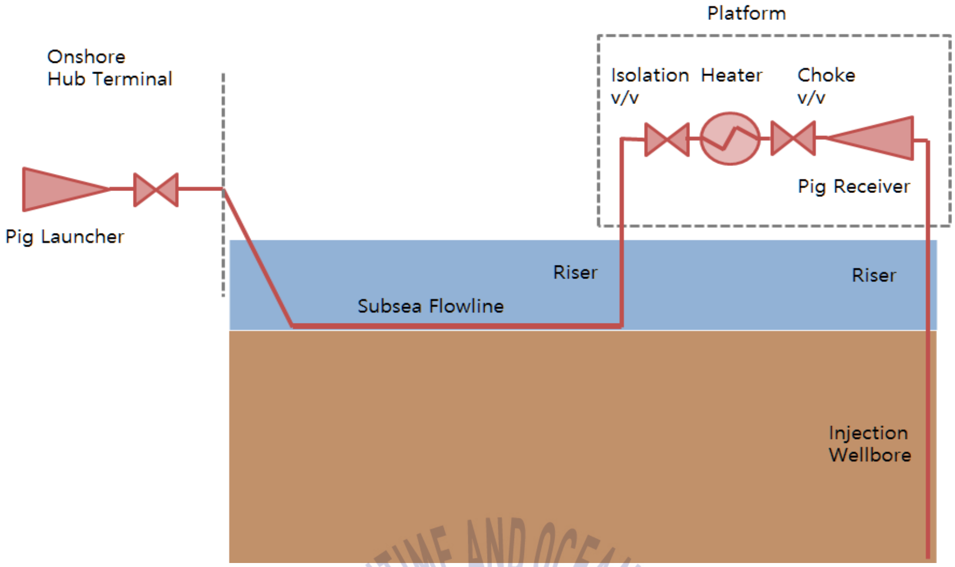

Fig. 1 Whole chain schematic of offshore CO_2 transport and injection systems(KRISO, 2016).

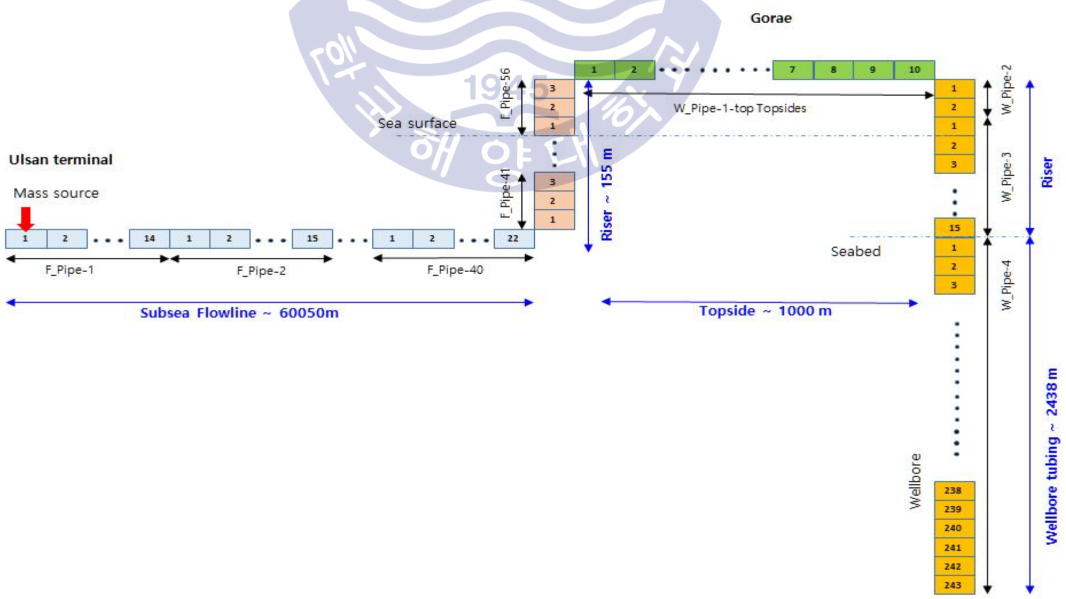

Fig. 2 Numerical model of offshore CO_2 transport and injection systems(min et al., 2016).

In this study, the CO_2 transport and injection system consists of subsea pipeline, riser, topside, and injection well. The subsea pipeline was designed to be installed along the seabed topography at about 60 km from the CO_2 temporary storage terminal on the coast to the point where the platform near the gas field was located. The riser has a length of about 155 m from the bottom of the pipeline to the topside, taking into account the depth of the platform and the height of the platform. It is assumed that the riser pipe has a radial gradient from the subsea pipeline outlet and is gradually changed vertically. The topside is designed to have pipelines, choke valves, isolation valves, heat exchangers, and so on. The topside pipeline is assumed to be 1 km in length, taking into account the pressure loss at the connections, bends, etc. The injection system consists of an injection riser located between the platform and the seabed, and an injection wellbore located from the seabed to the reservoir. The wellbore is designed to be installed vertically with a length of about 2400 m to the reservoir. The inner diameter of the system pipeline is 8 inches, which is the same for the entire system. In the previous research of this paper, the transport and injection pipeline, topside pipeline, and riser inner diameter were selected considering the pressure drop, flow rate, and the EVR (erosional velocity ratio) in a comprehensive manner (KRISO, 2016). Table 1 summarizes the subsea pipeline and injection wellbore design conditions for CO_2 transport and injection.

Table 1 Design conditions of subsea pipeline and wellbore(min et al., 2016)

Section	Size [in]	Inner diameter [mm]	Wall thickness [mm]	Insulation	
				Material	Thickness [mm]
Offshore	8	198.45	10.31	Carbon Steel	10.31
				Bitumen enamel	5
Wellbore	8	198.45	10.31	Carbon Steel	10.31
				Bitumen enamel	5
				Rock	360

2.1.2 Calculation Condition

Subsea pipelines for CO_2 transport are needed along the seabed topography from the temporary storage terminal to the seabed near the storage. To reflect this, the depth measurement data ETOPO1 (NOAA, 2016) measured by the National Oceanic and Atmospheric Administration was used and is shown in Fig.3

The ambient temperature conditions of the subsea pipeline, riser are applied to the seawater temperature corresponding to the installed depth. The ambient temperature was applied to the sea water temperature(KIOST, 2014) according to the depth measured by Korea Institute of Ocean Science and Technology, which is shown in Fig.4. In addition, it is assumed that the ground temperature from the seabed to the reservoir linearly increases from the seabed temperature of 8 ℃(KIOST, 2014) to the reservoir temperature of 97.8 ℃(KNOC, 2015).

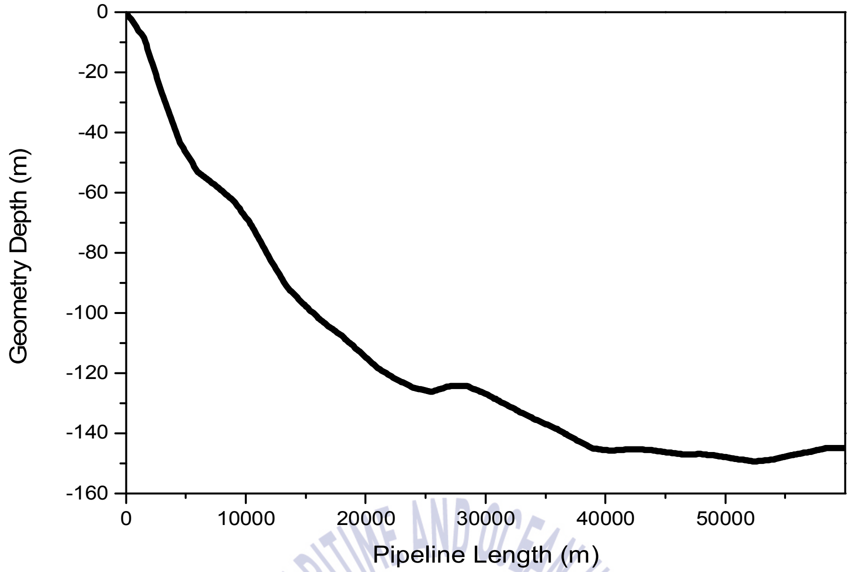

Fig. 3 Topography of subsea pipeline(min et al., 2016).

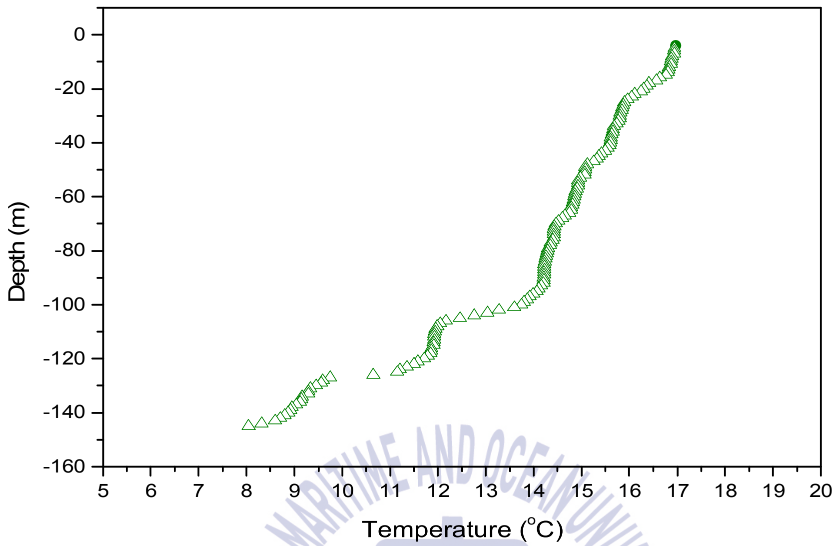

Fig. 4 Ambient temperature changes according to depth of seawater(min et al., 2016).

Table 2 summarizes the main calculation conditions for CO_2 transport and injection system in this study. The fluid in the system assumed pure CO_2. The CO_2 temperature at the inlet of the pipeline was assumed to be 25 ℃, taking into account the state of the pre-transport compression and cooling processes at the temporary storage terminal. The design pressure of the subsea pipeline was set at 157.4 bar to cover the operating pressure of the whole project period.

As mentioned above, the pressure of the gas reservoir rises with the passage of the injection period. The pressure of the reservoir due to the progress of CO_2 injection is referred to the modeling and simulation results of Korea National Oil Corporation(KNOC, 2015). Fig.5 shows the CO_2 flow rate and bottom hole pressure over the project period. The offshore CCS project period is 120 months. During the project period, the CO_2 flow rate was maintained at 31.5 kg/s and the CO_2 flow rate was reduced to 28.6 kg/s at the end of the project considering the reservoir pressure.

Table 2 Calculation conditions(min et al., 2016).

Calculation conditions	Design value
CO_2 Composition	100 %
CO_2 Flowrate	28.6~31.5 kg/s
Inlet Temperature at Hub Terminal	25 ℃
Design Pressure	157.4 bar
Reservoir Temperature	97.8 ℃
Number of Wells	1
Tubing Size	8 inches

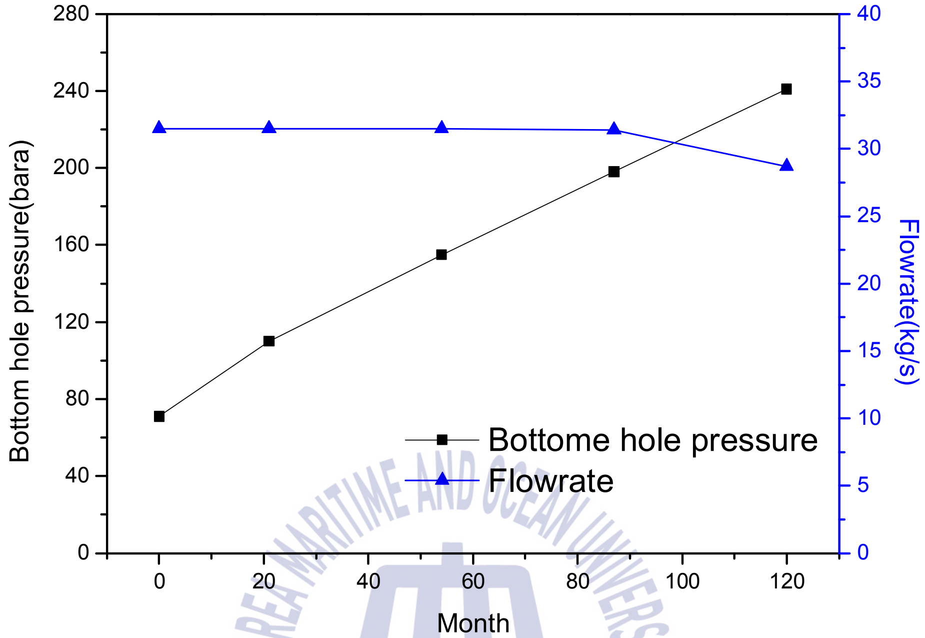

Fig. 5 Bottom hole pressure and flowrate variations over the injection period(min et al., 2016).

2.2 Result

2.2.1 CO_2 Behavior in Subsea Pipeline

Fig. 6 shows the change of CO_2 pressure according to the length of the subsea pipeline considering the injection time lapse. The inlet pressure of the subsea pipeline was calculated to be 70 bar at the beginning of the injection and 106 bar at the end of the injection. The calculated inlet pressure of the pipeline means the delivery pressure of the compression facility installed in the CO_2 temporary storage terminal. From the calculation results of the pipeline inlet pressure, the compression plant of the terminal should be able to handle the inlet pressure of the subsea pipeline throughout the whole injection period. In other words, it can be seen that the compression facility of the temporary storage terminal must be designed to be capable of delivering a delivery pressure of at least 70 bar to a maximum of 106 bar.

The pressure of CO_2 in the subsea pipeline along the direction of flow gradually increases from the inlet, and tends to decrease from about 13 km. This is because the pressure behavior in the seabed pipeline is affected by the topography shown in Fig.1. The pressure drop in the subsea pipeline consists of gravitational pressure drop and frictional pressure drop. In order to analyze the effect of these two on the pressure drop, the pressure drop gradient for each injection period and flow direction is shown in Fig.7 The solid line represents the pressure drop gradient due to gravity, and the dotted line represents the pressure drop gradient due to friction. Since CO_2 in the subsea pipeline is in a liquid or supercritical high density state during the whole injection period, no acceleration or deceleration pressure drop due to phase change occurred.

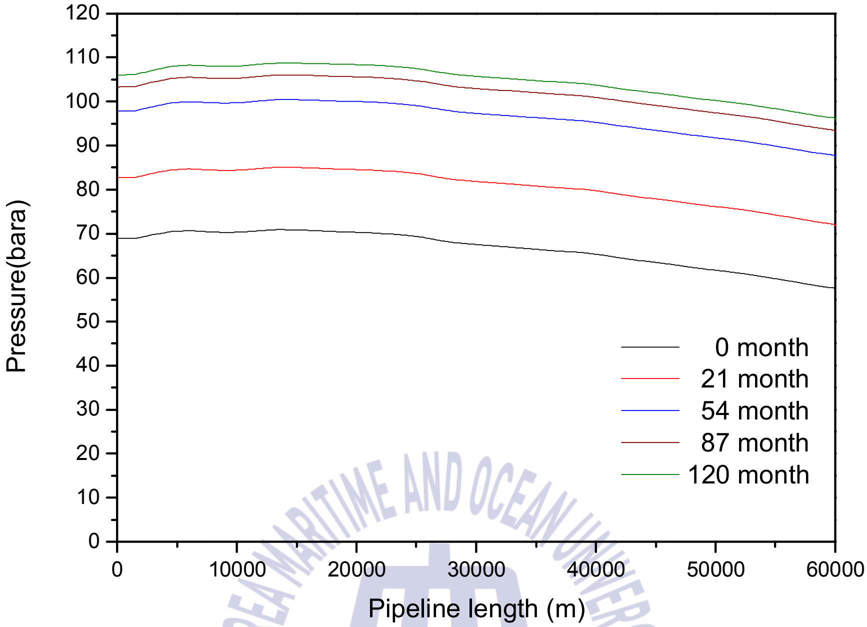

Fig. 6 Pressure profile of subsea pipeline(min et al., 2016).

The gravitational pressure drop gradient from the inlet of the subsea pipeline to about 30 km has a negative value. This is because hydrostatic pressure occurs due to the downward slope of the pipeline along the topography conditions, and the resulting pressure gain occurs. The frictional pressure drop gradient is a function of flow rate, fluid velocity, and diameter, and these do not vary with the injection period or flow direction. Therefore, the frictional pressure drop gradient shows a constant value.

The pressure behavior of the subsea pipeline as shown in Fig.6 is explained by the total pressure drop behavior considering both of the above mentioned pressure drops.

The CO_2 temperature according to the subsea pipeline length is shown in Fig.8. The temperature of the fluid in the pipe tended to decrease from the inlet temperature of 25 ℃ to the platform. The CO_2 temperature of the subsea pipeline is in thermal equilibrium at the same temperature as the seawater layer at that location, given the sufficient heat transfer with surrounding seawater. This temperature behavior also shows the same tendency over the entire injection period. In other words, the influence of the reservoir pressure behavior over the injection period on the temperature of CO_2 in the subsea pipeline is negligible, and the influence on the temperature of the surrounding seawater layer is predominant.

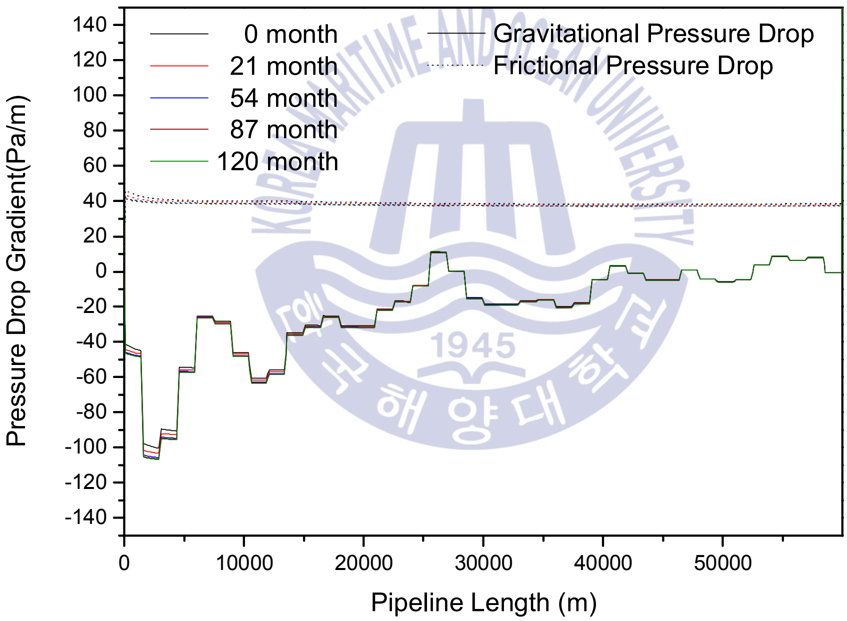

Fig. 7 Pressure drop gradient of subsea pipeline(min et al., 2016).

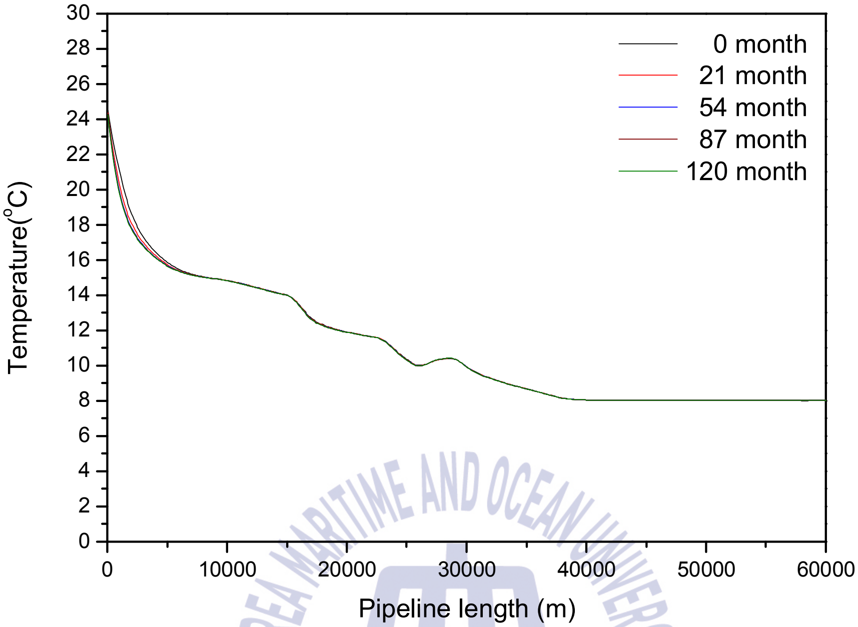

Fig. 8 Temperature profile of subsea pipeline(min et al., 2016).

2.2.2 CO_2 Behavior in Riser

The CO_2 pressure along the riser length direction is shown in Fig. The pressure in the riser in the flow direction tended to decrease linearly over the entire project period. This is due to the effect of the two pressure drops mentioned above. Especially in the riser, the gravitational pressure drop dominates as shown in Fig.10. In Fig.10, the reason why the slope of the gravity pressure drop is not constant is the result that reflects the section where the slope of the riser changes. The operating pressure of the riser gradually increased with the injection period.

As shown in Fig. 11, the temperature behavior of the riser is almost unchanged. The CO_2 temperature in the subsea pipeline is sufficient for heat transfer with surrounding seawater over a 60 km transport section, while CO_2

in the riser does not have sufficient heat transfer due to short transport distances and heat exchange times. Thus, the topside arrival temperature of CO_2 transported along the seabed pipeline can be considered to have a temperature equal to the temperature of the seabed near the topside. This could be used as a rule of thumb for future topside design.

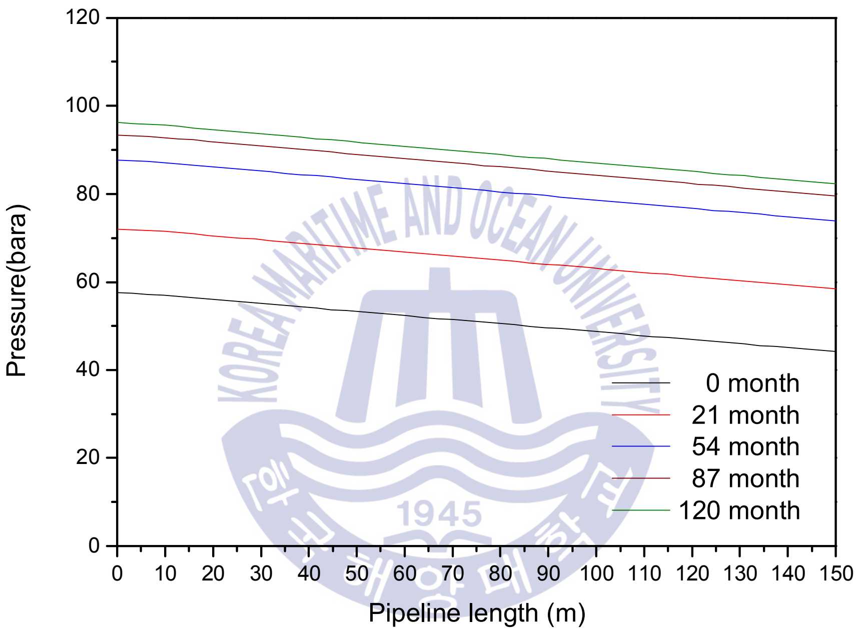

Fig. 9 Pressure profile of riser(min et al., 2016).

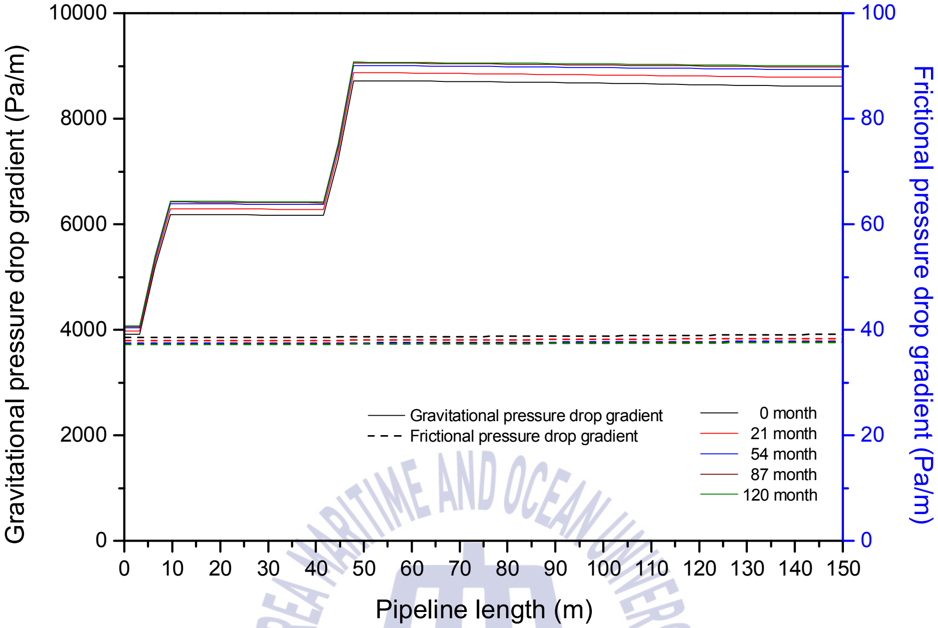

Fig. 10 Pressure drop gradient at riser(min et al., 2016).

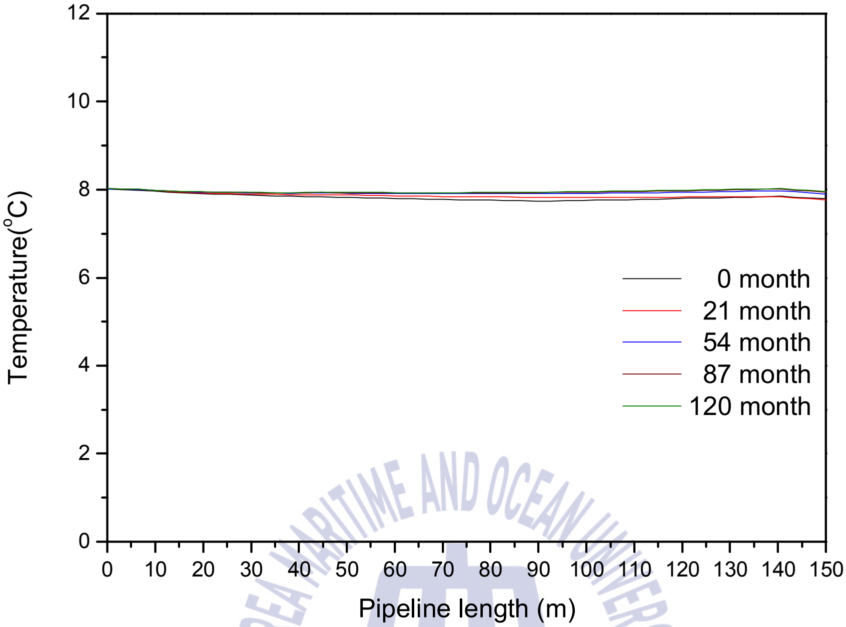

Fig. 11 Temperature profile of riser(min et al., 2016).

2.2.3 CO_2 Behavior at Topside

The CO_2 pressure in the flow direction in the topside pipeline over time is shown in Fig. On the topside, the process equipment as described in the previous chapter was installed and the length of the topside pipeline was set at about 1000 m. A heat exchanger is installed at about 650 m. The isolation valve is designed to be installed at 600 m and the choke valve at 700 m. This paper aims to simulate the steady state of CO_2 transport and injection system considering the pressure characteristics of the reservoir over injection time. Therefore, the choke valve and the isolation valve are fully opened, and the diameter of the valve is set equal to the diameter of the system, so there is no pressure fluctuation due to the valve. Since there is no detailed information on the heat exchanger, it is assumed that the pressure drop by the heat exchanger is negligible. The pressure along the flow direction of the topside pipeline is shown in Fig.12. The pressure behavior of CO_2 in the topside is governed by frictional pressure drop in the pipeline and the pressure drop is negligible. The increase of the operating pressure of the topside due to the project period showed similar trend to the subsea pipeline and riser.

When considering the pressure and temperature of CO_2 injected into the reservoir, it is injected into the gaseous state at the beginning of the project period, and most of it is stored in the supercritical state. On the other hand, the CO_2 in subsea pipelines and risers is in a subcritical liquid state at the beginning of injection and it changes from to supercritical with time. This implies that if there is no proper topside process, two-phase flow can occur anywhere in the entire system. If a phase change occurs in the subsea pipeline, flow instability due to two-phase flow and acceleration / deceleration pressure drop may occur. In addition, if it occurs in the vertical injection well, the boundary between gas phase and liquid phase is formed and CO_2 injection bubbles flowing in the opposite direction of flow may cause difficulty in wellhead control. In this paper, this in order to avoid situations such proposes to control the injection before, CO_2 pressure and temperature in the heating process of topside of the platform.

The CO_2 arriving at the topside until the injection period of 53 months is liquid state. On the other hand, CO_2 in the injection sump is in the gaseous state. Therefore, the liquid phase CO_2 was converted into the gaseous phase by controlling the temperature through the heat exchanger at the topside, and the set temperature of the heat exchanger is as shown in Fig.13.

After 54 months of injection, the state of the CO_2 at the topside is converted to a supercritical state. This means that the topside facility is operating near the critical point of CO_2 at this stage and careful operation of the topside process is needed. CO_2 near the critical point shows abrupt changes in physical properties even at small pressure and temperature changes, which can lead to uncontrollable flow of the system or unstable flow. To avoid this, the temperature condition was raised above the critical point temperature through the topside heat exchanger as shown in Fig.13. Therefore, when designing the topside heat exchanger, the phase behavior of CO_2 in the system should be carefully analyzed. Based on this result, the required energy and capacity of heat exchanger should be optimized by considering the required heating temperature and the area required for installing the topside process.

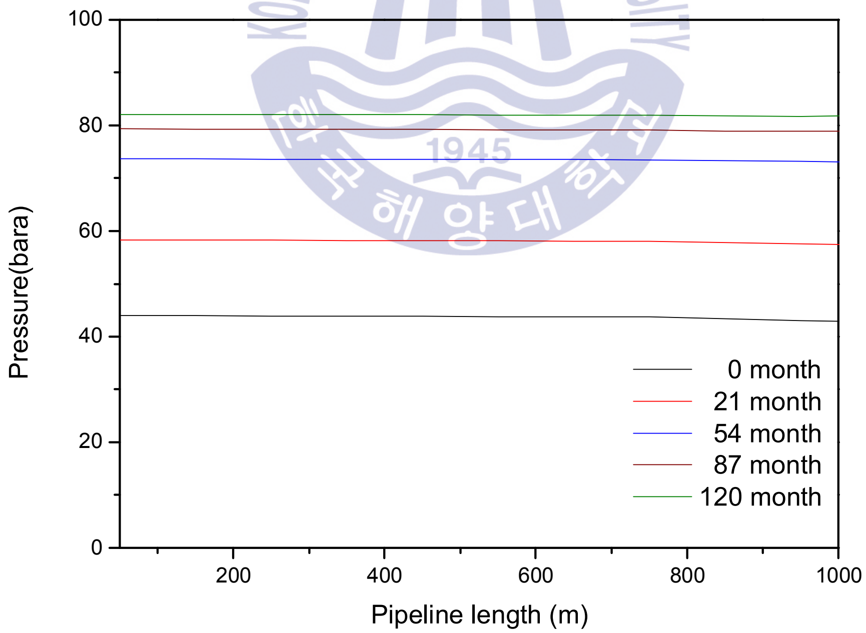

Fig. 12 Pressure profile of topside pipeline(min et al., 2016).

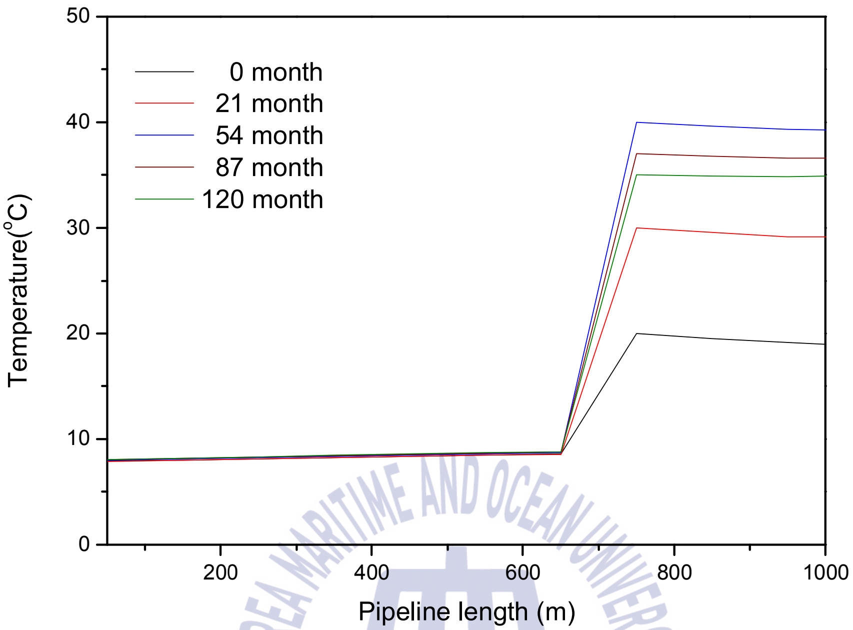

Fig. 13 Temperature profile of topside pipeline(min et al., 2016).

2.2.4 CO_2 Behavior in Injection Wellbore

The behavior of CO_2 injection wellbore was calculated and analyzed. The pressure of the CO_2 in the injection wellbore with the passage of time is shown in Fig.14. As the reservoir pressure increased, the pressure in the injection wellbore increased and the pressure gradient along the wellbore length increased. As shown in Fig.15, it can be seen that the gravitational pressure gain is caused by hydrostatic pressure because the injection well is vertically installed. The gravitational pressure gain increases with the duration of the project. This is due to the increase in the CO_2 density as a result of the change from the initial gas phase to the supercritical state in the middle and late stages of the project and hence the hydrostatic pressure. As shown in Fig.16, the frictional pressure drop decreased with the duration of the operation. The gaseous CO_2 at the beginning of the project period is less dense than the supercritical CO_2 at mid and later stages of the project period, and therefore the velocity of flow in the wellbore is fast. However, as the injection period elapsed, the phase changed and the velocity of flow slowed down and frictional pressure drop, which is a function of the velocity of flow, tended to decrease. From this, it can be understood that the pressure behavior at the injection well is dominantly influenced by the pressure gain caused by the hydrostatic pressure.

The temperature behavior of injection wellbore CO_2 is shown in Fig.17. As described in the topside analysis above, the temperature of the CO_2 injected into the wellbore varies with time due to the phase change control. The injection system in this study consisted of an injection riser exposed at seawater and a wellbore installed in the underground. Therefore, due to the difference in boundary conditions between these ambient temperatures, The tendency of temperature change of CO_2 showed a slightly different tendency in the injection riser and injection wellbore as shown Fig.17. The boundary condition of the ambient temperature in the underground was linearly increased from the seabed temperature to the reservoir temperature of 97 ℃. Due to this ambient temperature condition, the CO_2 temperature in the injection well tends to increase with the flow direction.

The CO_2 temperature behavior in the injection wellbore increased with the passage of time, but decreased after the injection period of 54 months. Also, the tendency of the temperature change along the length also tended to change with the passage of time. This is due to the change in the pressure and temperature of the injection wellbore over injecton time, leading to the transition to the state of supercritical CO_2, which results in a change in the specific heat of the CO_2. As shown in Fig.18, the CO_2 near the inlet of the injection wellbore approaches the supercritical state as the time elapses, and the heat capacity increases with the increase of the specific heat. The large heat capacity means that the temperature change of the CO_2 in the injection wellbore is small at the same ambient temperature boundary condition and heat transfer rate. Therefore, the temperature gradients of CO_2 in the injection wellbore show different tendency with injection time.

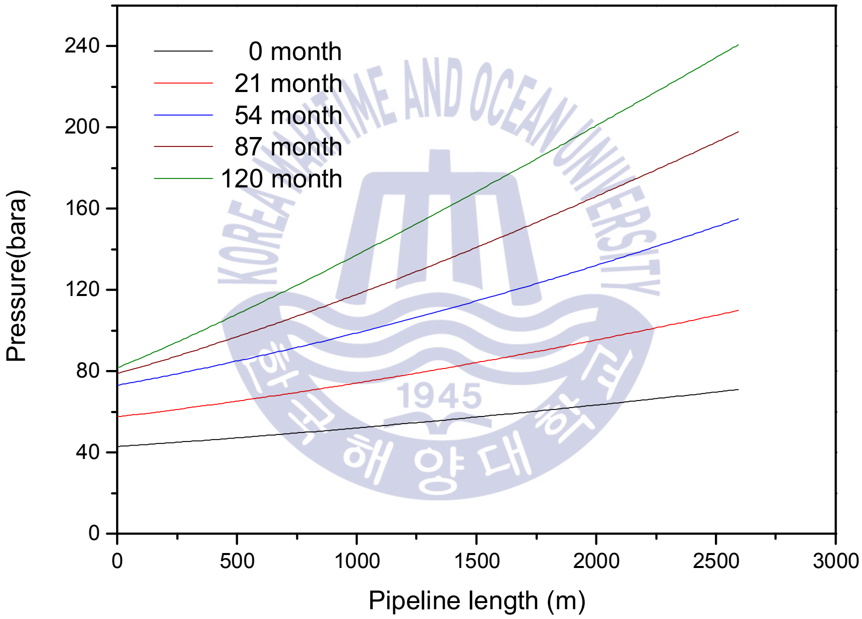

Fig. 14 Pressure profile of wellbore(min et al., 2016).

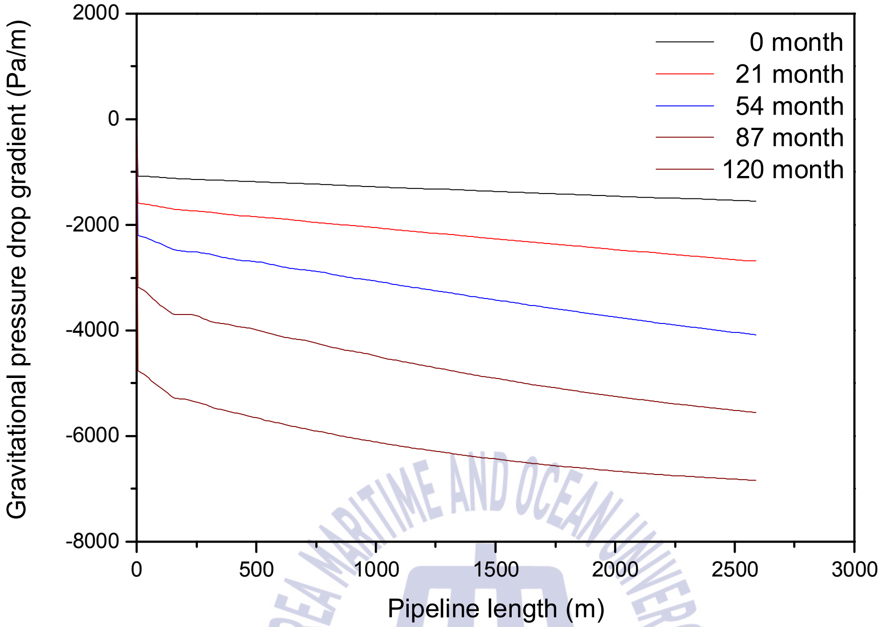

Fig. 15 Gravitational pressure drop gradient of wellbore(min et al., 2016).

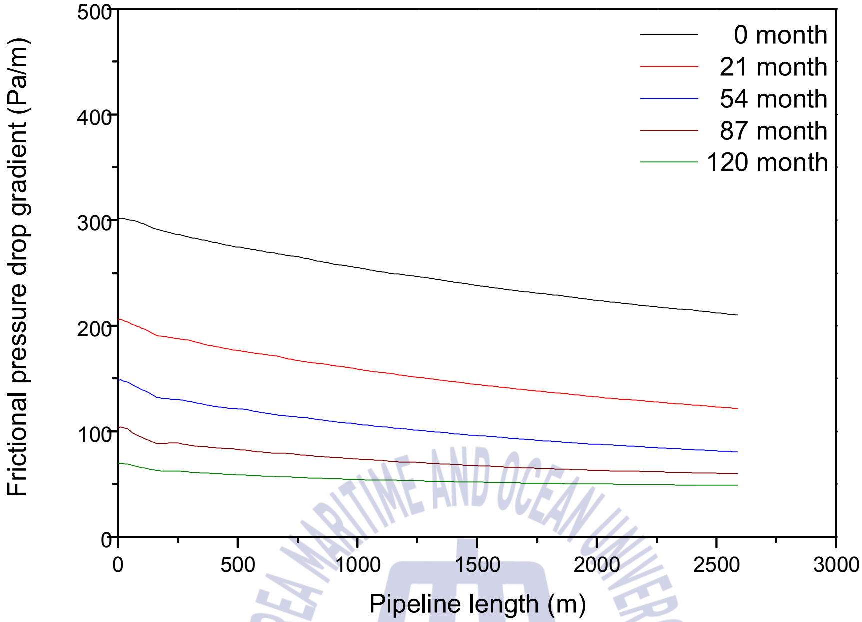

Fig. 16 Frictional pressure drop gradient of wellbore(min et al., 2016).

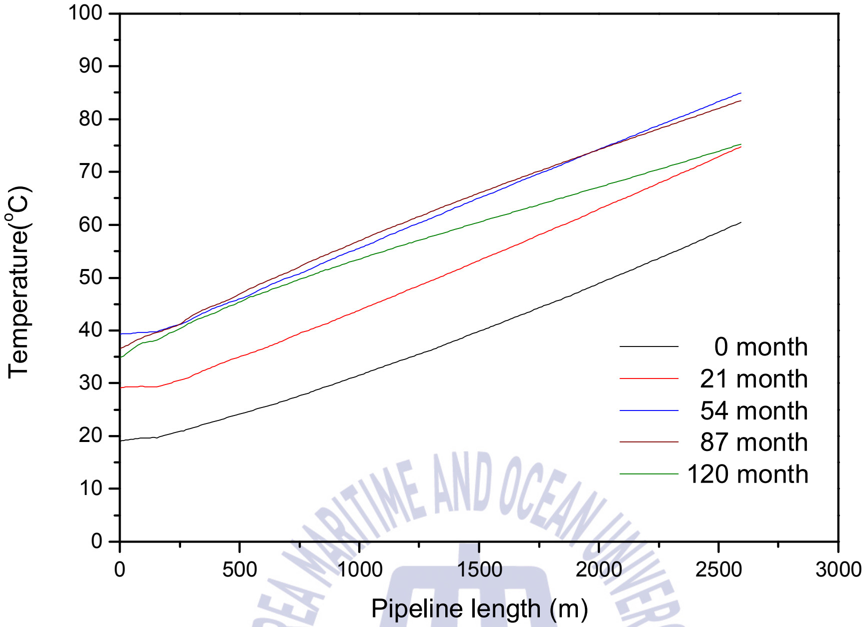

Fig. 17 Temperature profile of wellbore(min et al., 2016).

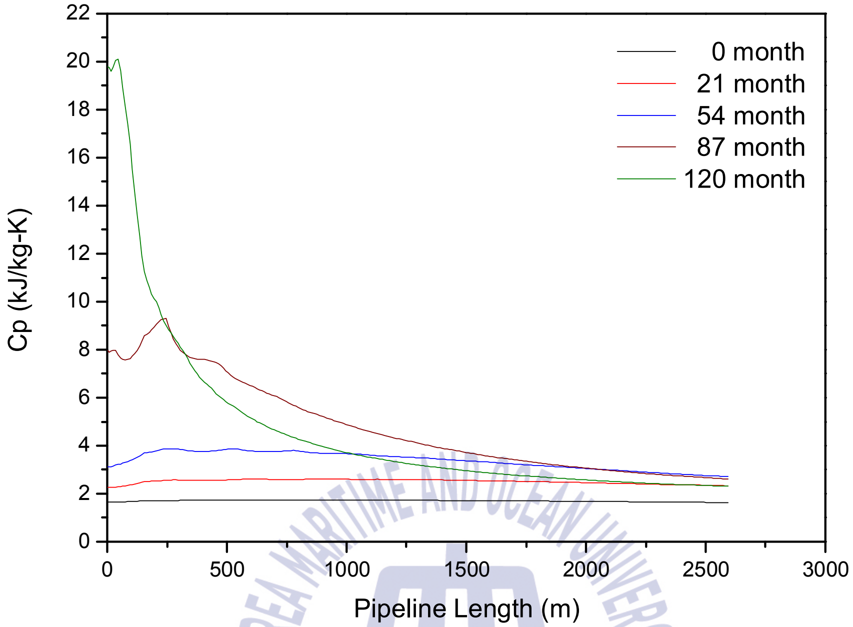

Fig. 18 Specific heat change along the wellbore(min et al., 2016).

2.2.4 Phase Behavior of the Whole System

The phase behavior of CO_2 was analyzed in the entire system constructed in this paper. Since the CO_2 used in this study assumes pure CO_2, the phase envelope has a form of a single saturation line as shown in Fig.19. In the temperature-pressure diagram of Fig.19, the phases are classified into five regions based on the critical point. The names and conditions of each area are summarized in Table 3.

As mentioned in the previous section, in the early period of injection (0 ~ 53 months), CO_2 is changed from liquid state to gaseous state at the topside. In the middle and late period of injection (54 ~ 120 months), CO_2 is changed from liquid-like supercritical to gas-like supercritical at the topside.

CO_2 in the subsea pipeline changes from ③ to ① as the project period passes. From the above results, CO_2 with liquid-like supercritical state and liquid state is not much different in terms of pressure and temperature behavior. At the start of the project, the CO_2 status in the injection wellbore changes from ④ to ⑤. As business time passes, the state of CO_2 passing through the topside heat exchanger will pass near the critical point at 54 months. CO_2 at the critical point shows unstable behavior due to rapid changes in physical properties even at small temperature and pressure changes, but, since the time to pass through the critical point of CO_2 in the heating process through the heat exchanger is very short, and the sections before and after the heat exchanger are very small, notable flow instability in the system did not appear.

Table 3 Definition of CO_2 Phase(min et al., 2016)

State	Condition	Remark
Liquid-like supercritical	$T<T_C$, $P>P_C$	①
Supercritical	$T>T_C$, $P>P_C$	②
Liquid	$T>T_{sat}$, $P>P_{sat}$	③
Gas	$T<T_{sat}$, $P<P_{sat}$	④
Gas-like supercritical	$T>T_C$, $P<P_C$	⑤

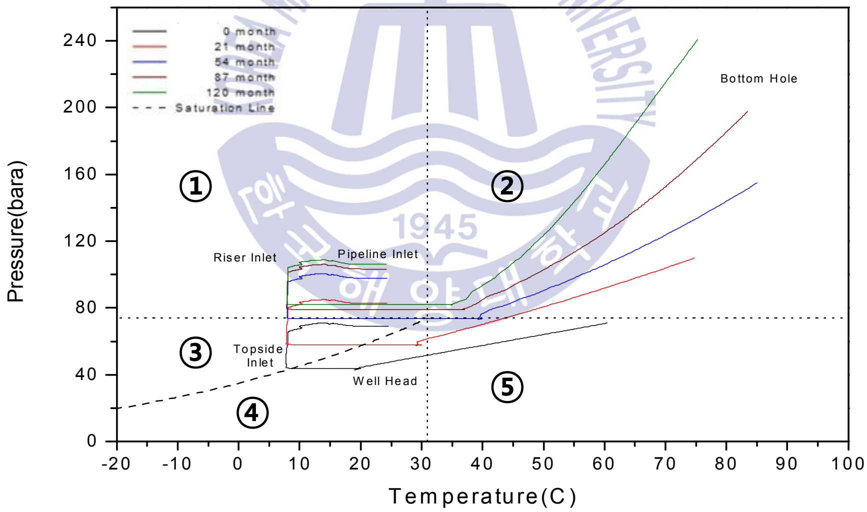

Fig. 19 P-T diagram of hole system(Min et al., 2016).

The state of CO_2 in the injection wellbore changes from ⑤ to ② as the project period passes. This results in an increase in the density of CO_2 in the injection well and a difference in heat exchange between the CO_2 in the wellbore and the surrounding geothermal gradient due to the change in specific heat. This behavior is confirmed in the previous section, which affects the temperature behavior of CO_2 in the injection wellbore.

Comparing the CO_2 phase at the inlet of the subsea pipeline and bottom hole of injection wellbore, the CO_2 phase behavior changes dramatically with the passage of the project period. In other words, at the beginning of the project, the state of CO_2 emitted from the CO_2 temporary storage terminal is liquid state, and the state of CO_2 at the bottom hole of injection wellbore stored in the reservoir is gas-like supercritical phase. On the other hand, in the later period of the project with high reservoir pressure, the state of CO_2 emitted from the CO_2 temporary storage terminal is in liquid-like supercritical state phase, and the state of CO_2 at the bottom hole of injection wellbore is supercritical state. Therefore, the CO_2 compression facility to be installed in the temporary storage terminal should be designed to handle both liquid-like supercritical state and liquid phase.

During the injection period, it is necessary to analyze the energy consumption of the heat exchanger for efficient process design of the above-mentioned equipment installed on the topside. The operation of the heat exchanger in the proposed system is divided into two purposes. In the early part of the project (0 ~ 53 months), it is used to inhibit the two-phase flow of the subsea pipeline and CO_2 in the injection well and to make phase changes at the topside. In the latter half of the project period (54 ~ 120 months), it is used to avoid the near critical point flow at the topside pipeline and to control wellhead.

The energy required for the heat exchanger was the largest at the beginning of the injection, which was largely due to the latent heat of vaporization required to convert liquid CO_2 to gaseous CO_2. The analysis of the energy required for the topside heating process and the new process for reducing it will be described in the next section.

Chapter 3 Energy Saving Method for CO_2 Injection Process

3.1 CO_2 Injection Process

The results in the previous section show that there is a difference in CO_2 between the subsea pipeline and the injection well. Therefore, if the injection system does not control the phase of the CO_2, the phase behavior can cause the CO_2 to flow abnormally in any part of the system. Because CO_2 is phase bounded by a single saturating line, the phase of CO_2 can change under small pressure and temperature changes. The phase change of CO_2 leads to dramatic changes in properties such as specific volume and density. Thus, changes in operating conditions at temperatures and pressures near the saturation line make the transport and injection system unstable. In order to keep the flow in the pipeline, riser and injection well in a single phase, artificial phase change control in the offshore platform is required. Conventional CO_2 injection processes change the liquid CO_2 to gaseous CO_2 by increasing the temperature of the CO_2 through a heat exchanger located at the topside of the platform. However, the existing process is not economical due to the high energy consumption, considering the conditions of the platform located in the offshore area. To overcome these shortcomings of the existing process, this study proposed a new process that can be applied to offshore platforms. Unlike the existing process, the newly proposed process reduces the energy consumption by phase separation in the separator and utilizing the seawater heat source and the compressor discharged heat. In addition, the numerical analysis of the proposed new process compares the energy consumption with the existing process, and the key design parameters were derived through parameter studies. This study deals with the phase transition process of CO_2. To analyze the phase change control, the numerical simulations were carried out up to 54 months. After 54 months, it is assumed that CO_2 was transported and injected as the supercritical phase.

3.1.1 Conventional Process

The conventional phase change process is shown in Fig.20, and the heat energy required for the heater in the platform was calculated and analyzed. The existing CO_2 phase change process is the process of heating liquid CO_2 through a heater and converting it to gaseous CO_2. As shown in Fig.13 of the previous chapter, the topside arrival temperature is about 2.7 ° C regardless of the injection period. It is assumed that the pressure drop of the heater can be ignored because there is no detailed design information of the heater. The energy required to heat CO_2 is summarized in Fig.21. A parametric study of the heater setting temperature was performed and the required minimum temperature and the required energy were calculated. As the operating pressure increased over the injection period, the heat energy required for the Latent heat of vaporization decreased. Despite being the highest heating temperature at 54 months, the required thermal energy is maximum at 0 months. That is, a large amount of thermal energy must be supplied to the topside of the platform at the start of the CO_2 injection project. However, because the ocean platform with the CO_2 injection facility, such as a heater, is located at more than 60 km from the land. It is both inefficient and uneconomical to supply huge amounts of thermal energy on land using pipelines, wires or fuel carriers. Therefore, the lower the energy required for the topside process, the more economically the CO_2 transportation and injection business will proceed.

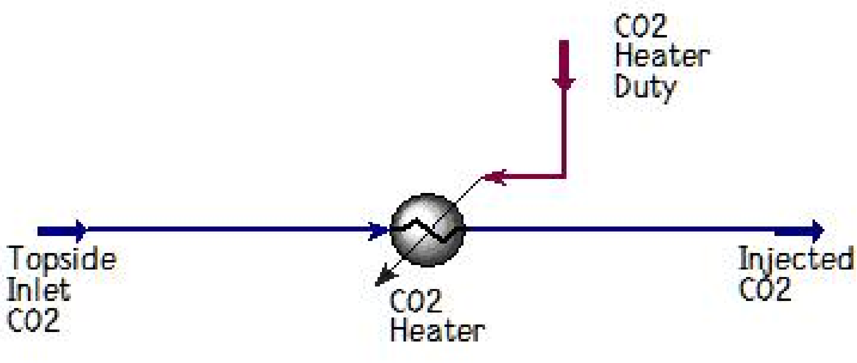

Fig. 20 Conventional offshore heating process(Min & Huh, 2017).

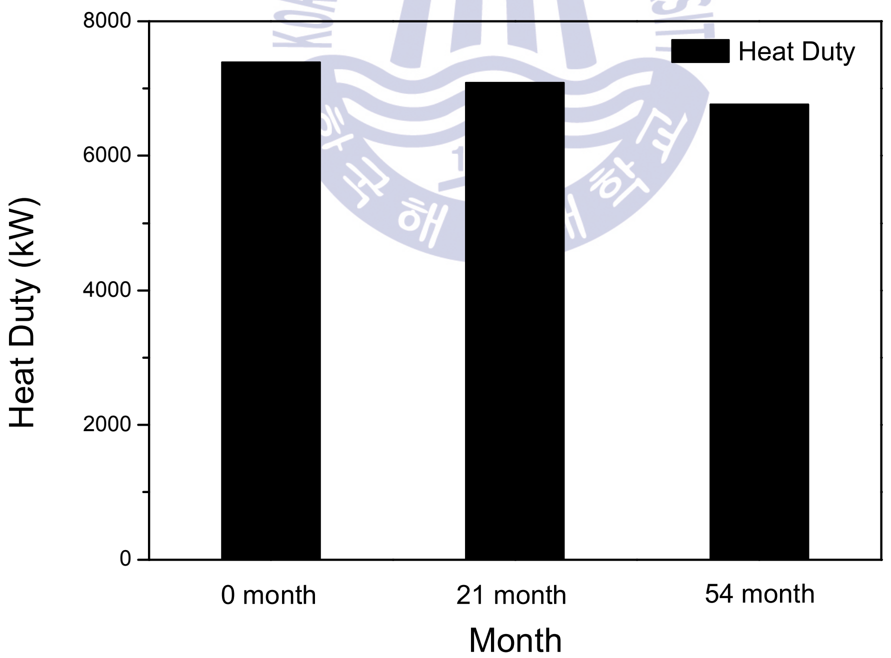

Fig. 21 Energy required for the conventional heating process over the injection period.

3.1.2 New Process Using Seawater and Compressor Discharge Heat

A new process using a seawater heat source and a compressor discharge heat source has been proposed to reduce significant energy consumption of the existing process in the topside process, as shown in Fig. Comparisons of energy requirements of existing and proposed new processes were performed by numerical calculations. In the proposed new process, the liquid CO_2 arriving at the topside is decompressed through a CO_2 separator and separated into gas phase and liquid phase. Because some gaseous CO_2 is produced by depressurization rather than by heating, the amount of heat energy required for latent heat of vaporization can be reduced. In addition, because the temperature of liquid CO_2 at the outlet of the separator is very low due to the Joule-Thomson cooling with decompression process, the temperature difference between the surrounding seawater and liquid CO_2 is greater than that in the conventional method. This means that it is possible to gain thermal energy from the seawater in the proposed new method. To compensate for the pressure drop of liquid CO_2 at the outlet of the separator, the separated liquid CO_2 is pressurized through a CO_2 pump. In consideration of this temperature difference, a seawater heat exchanger is added. Therefore, it is possible to reduce the energy required to change the liquid CO_2 into a gas that is suitable for injection when compared with the conventional method of using the heater. To inject CO_2 that has been changed to gas, the pressure was increased using the CO_2 compressor. The discharge CO_2 temperature of the compressor is high by virtue of the compression process. The high temperature of compressed gaseous CO_2 additionally heats the liquid CO_2 that is discharged from the seawater heater. To allow the thermal energy exchange between the seawater heater outlet CO_2 stream and the discharged CO_2 stream from the compressor, a compressor aftercooler is suggested (Fig. 22). Finally, the liquid CO_2 stream at the outlet of the after cooler is heated using a CO_2 heater to meet the required injection conditions. In the proposed new method, the seawater discharge temperature of the seawater heat exchanger and the pressure drop of the separator are important design parameters. The energy consumption of the topside differs depending on the temperature of the discharged seawater. In addition, depending on the value of the pressure drop in the separator, the flow rate of the gas and liquid CO_2 changes, and the energy required for the topside process equipment is also affected by the change in temperature and pressure of the CO_2. This is described in more detail in the next section. To compare the two methods, the pressure and temperature conditions of CO_2 arriving at the topside and the CO_2 injected through the process in the new process were set to be the same as those of the conventional process.

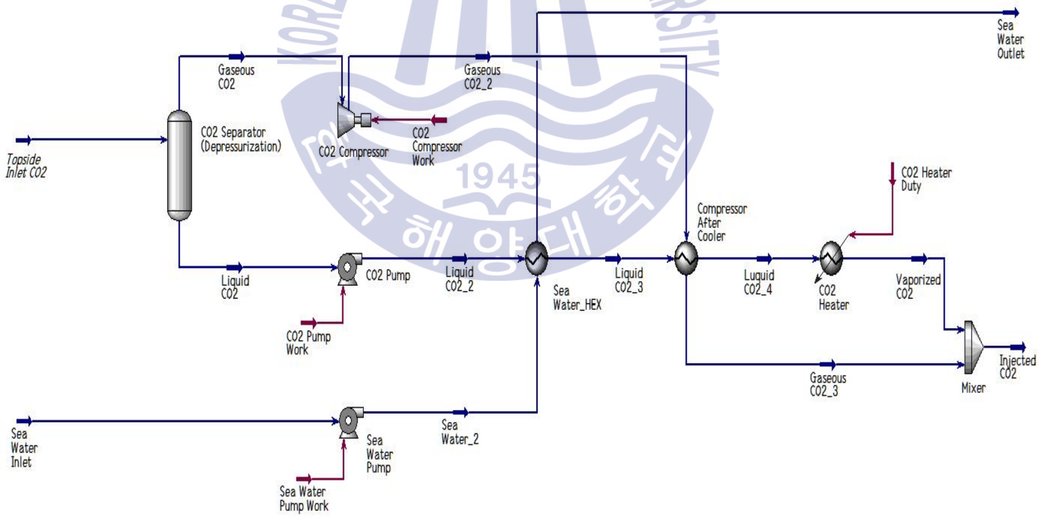

Fig. 22 A new offshore heating process using seawater and compressor discharge heat(Min & Huh, 2017).

3.2 Parameteric Study of Proposed New Process

3.2.1 Influence of Seawater Discharge Temperature

The separated liquid CO_2 was heated by the seawater heat source. Subsequently, additional heat energy was supplied by the compressor after cooler and CO_2 heater to make the liquid CO_2 into injectable gaseous CO_2. The additional energy consumption of the CO_2 heater is closely related to the seawater temperature emitted from the seawater heat exchanger. As shown in Fig. 22, liquid CO_2 exchanges heat with seawater around the offshore platform. To reduce the heat required in the CO_2 heater, heat exchange between liquid CO_2 and seawater should be maximized. In other words, the lower the temperature of the discharged seawater, the lower the energy required for the CO_2 heater, thus reducing the energy required for the topside. On the other hand, the sea water that is cooled and discharged may affect the surrounding environment. Therefore, the temperature of sea water discharged should be limited to minimize the effect of cooled sea water on the environment of the platform.

The effect of seawater discharge temperature is analyzed by assuming that the pressure drop through the separator, which is another key parameter, is constant. The pressure drop from the separator is 25 bar for 0 month, 35 bar for 21 months, and 45 bar for 54 months. The reasons for the different pressure drop of the separator over the injection period will be explained in detail in the next section. Because the separator pressure drop across each injection period is constant, the flow rates of liquid CO_2 and gaseous CO_2 throughout the process are constant. Also, the flow rate of the seawater and the head of the seawater pump were set to be constant.

Based on the above assumption, the energy consumption of the CO_2 heater is only affected by the temperature of the seawater discharged. The total energy required for the proposed new process is the sum of the energy required for a CO_2 pump, a CO_2 compressor, a seawater pump, and a CO_2 heater. Gas and Liquid CO_2 and seawater flow rates are constant and the pressurization amount is also constant, so the energy required for CO_2 compressors, CO_2 pumps and seawater pumps is constant. The energy requirement for injection period of 0 months(separator pressure drop 25 bar) for CO_2 compressor, CO_2 pump, and seawater pump is shown in Table 4.

Table 4 Energy requirement for equipment

Topside process equipment	Power requirement (kW)
CO_2 compressor	286.91
CO_2 pump	80.94
Seawater pump	191.53

In order to analyze the influence of the discharged sea water temperature, the energy demand of the CO_2 heater was calculated by changing the temperature difference between the surrounding sea water and the discharged sea water. The calculated energy requirement is shown in Fig. 23 considering the temperature difference between the surrounding seawater and the discharged seawater at 0 month of injection period. As the temperature difference between the surrounding seawater and the discharged seawater increases, the energy required for the heater tends to decrease. However, considering the above-mentioned effect of the discharged seawater on the surrounding environment, t, the temperature difference between the discharged seawater and the natural seawater could be limited up to 6 ℃.

With respect to the temperature of effluent seawater, the difference between the intake and drainage water is specified to be 7 ℃ to 9 ℃ at the outlet in Japan, and 4 ℃ or less in Taiwan, at a distance of 500 m from the outlet. In Italy, it is specified to be below 3 ℃ at a distance of 1 km from the outlet (KEI, 2013). In this study, we assumed that the difference between discharged and natural seawater temperatures was limited to less than 6 ℃. In other words, the natural seawater temperature is 26 ℃ in summer, so the temperature of the discharged water is assumed to be at least 20 ℃. Since the natural seawater temperature in winter is 12 ℃, the temperature of discharged seawater is assumed to be at least 6 ℃. Therefore, as listed in Table 5, the total energy requirement of the proposed method is reduced by 14-18 % compared to the conventional method.

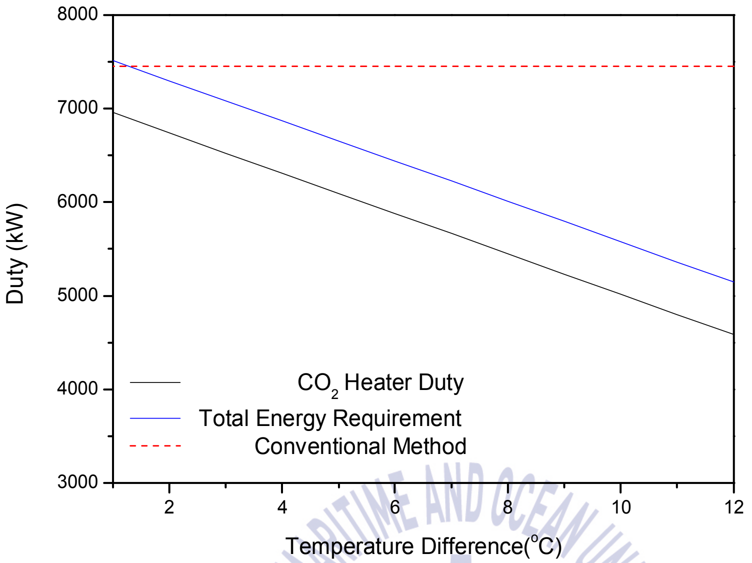

Fig 23. Energy requirement depending on differences in seawater temperature at the o month(Min & Huh, 2017).

Table 5 Comparison of conventional and new processes

Month	Equipment	Required Energy (kW)		
		New Method	Conventional Method	Energy Consumption Ratio
0	CO_2Compressor	286.9	7449	
	CO_2Pump	80.9		
	CO_2Heater	5877.3		
	Seawater Pump	191.5		
	Total	6436.6	7449	0.86
21	CO_2Compressor	266.9	7140	
	CO_2Pump	122.4		
	CO_2Heater	5406		
	Seawater Pump	191.5		
	Total	5986.8	7140	0.84
54	CO_2Compressor	164.1	6807	
	CO_2Pump	175.7		
	CO_2Heater	5116		
	Seawater Pump	191.5		
	Total	5647.3	6807	0.82

3.2.2 Effect of Separator Pressure Drop

The relative amount of liquid and gaseous CO_2 at the outlet of the separator depended on the pressure drop at the separator. In other words, the energy requirements at the offshore platform were governed by the pressure drop of the separator. Based on the results in the previous section, the temperature difference between the surrounding seawater and the effluent water was assumed to be 6 ℃. The energy requirements of the offshore platform facilities, including the pump and compressor, depended on the pressure ratio and flow rate variations due to the pressure drop of the separator.

The larger the pressure drop, the lower the energy requirement of the heater because the flow rate of liquid CO_2 was reduced. At the same time, however, the flow rate of CO_2 in the gaseous state increases, so the energy requirement of the compressor increases. Fig. 24 shows the mass flow rates of liquid CO_2 and gaseous CO_2 varying with the separator pressure drop. The energy required for the heater and the compressor change with the mass flow rate due to the pressure drop is shown in Fig. 25. In addition, the larger the pressure drop in the separator, the greater the pressure differential that the CO_2 pump must recover, but the increment of the energy required by the pump is small because of the decrease in the liquid CO_2 flow rate. The work required for the CO_2 pump is also a small fraction of the total energy consumed.

There is a minimum pressure drop value that allows phase separation in the CO_2 separator. In addition, the variations in BHP with injection period results in different pressure drops. The higher the BHP, the higher the operating pressure of the system. This results in an increasing pressure drop to produce gaseous CO_2 at a given operating pressure. If the pressure drop in the separator is not sufficient, CO_2 phase separation does not occur. Consequentially, since evaporative cooling is not enough, heat exchange with seawater becomes inefficient and the compressor and compressor waste heat cannot be used. The minimum pressure drop values for making gaseous CO_2 over all time periods are summarized in Table 6.

The work input to the pump and the compressor and the heat input to the heater have different energy sources. The work for the pump and the compressor uses electricity. Depending on the design conditions, the energy used in the heater can be either electric or fired heating energy. If fired heaters are installed, more space and equipment should be added to store the fuel in the platform, which will increase the weight of the platform. If electric heaters are used, a lot of electric power is consumed, which can cause uneconomical problems. No matter which heaters are installed, it is better to minimize the consumed energy; it is necessary to select appropriate working conditions for the compressor and pump according to the pressure drop of the separator considering the management of energy utilization and consumption in the offshore platform.

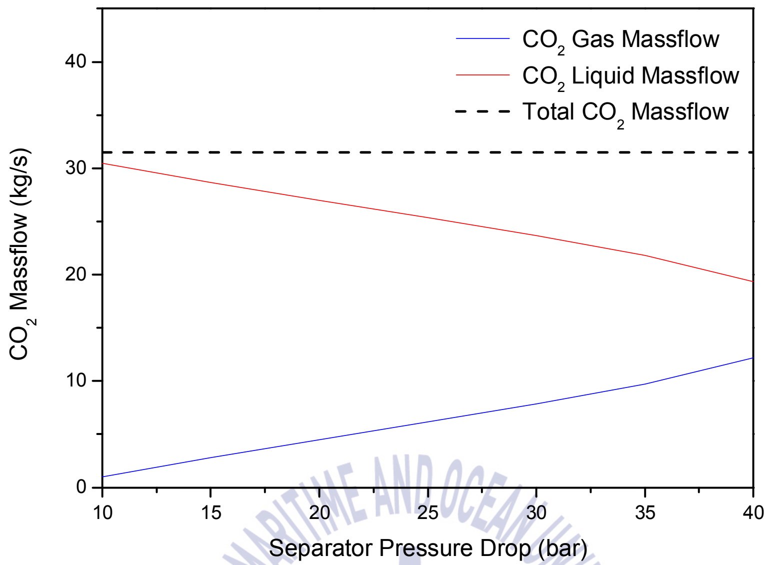

Fig. 24 Mass flow rate of gas and liquid CO_2 with respect to pressure drop(Min & Huh, 2017).

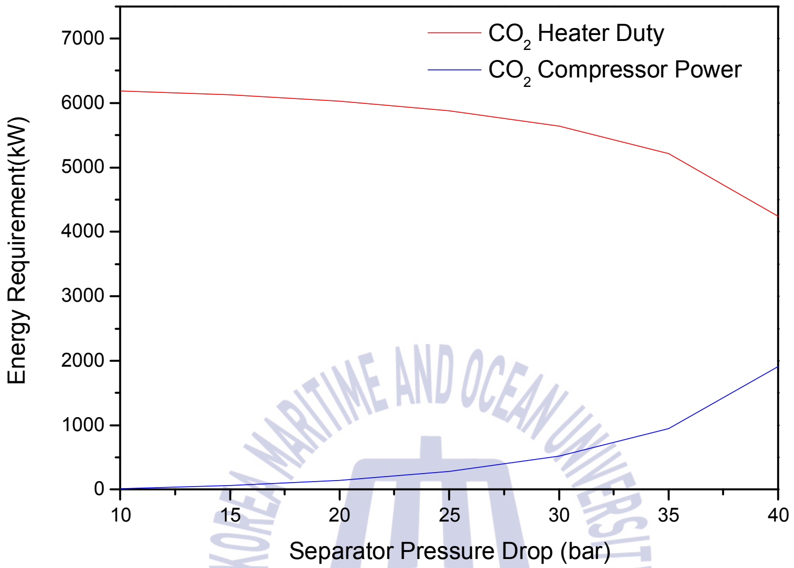

Fig. 25 Required energies for the heater and compressor with respect to pressure drop(Min & Huh, 2017).

Table 6 The minimum pressure drop values in the separator for making gaseous CO_2 over all time periods

Month	Bottom hole pressure (bar)	Minimum pressure drop values for making gaseous CO_2 (bar)
0	71	10
21	155	21
54	155	33

Chapter 4 Conclusion

4.1 Analysis of CO_2 Transportation and Injection System

In this study, the CO_2 behavior in the system considering the pressure behavior of the reservoir was analyzed by numerical analysis when the depleted gas field in the East Sea of Korea was used as CO_2 storage site. The entire system consists of a subsea pipeline, a riser, a topside and an injection well, which are designed and analyzed through OLGA 2014.1. CO_2 pressure, temperature, and phase behavior in the subsea pipeline, riser, topside, and injection wells were analyzed during an injection run of about 10 years. Through this, design methods such as subsea pipeline inlet compressor, topside process equipment, and injection wellhead control method were suggested. The conclusions of this study are as follows.

(1) The inlet pressure of the subsea pipeline, that is, the CO_2 temporary storage terminal compression facility, shall be designed for the end of the project at which the storage pressure is at its maximum. In the pressure behavior of the subsea pipeline, the pressure gain due to gravity is dominant near the shore and the pressure loss due to friction is dominant as it approaches the offshore platform near the reservoir.

(2) The CO_2 temperature in the subsea pipeline is less affected by the reservoir pressure behavior over time and is dominantly influenced by the corresponding seawater temperature. Since the CO_2 temperature change in the riser is very small, the temperature of the CO_2 arriving at the topside can be designed to follow the seabed temperature. The temperature of CO_2 in the injection well increases with the flow direction due to the geothermal

gradient. However, as the injection period elapses, the temperature gradients in the injection wellbore are different. This is due to the fact that the CO_2 changes into the supercritical state with the passage of the injection period, and the heat capacity changes due to the change in density and specific heat.

(3) Since the temperature and pressure conditions of the subsea pipeline and the reservoir are different over the entire injection period, the state of the injection wellhead CO_2 should be controlled through the heat exchanger at the topside of the offshore platform for the operational safety of the entire transport and injection system. That is, at the beginning of the injection, the state of CO_2 emitted from the hub terminal is liquid phase, and the state of CO_2 at the bottom hole of the wellbore is gas-like supercritical state. On the other hand, in the post-injection period, the state of CO_2 emitted from the hub terminal is liquid-like supercritical state and the state of CO_2 at the bottom hole of the wellbore is supercritical state. The performance of the topside heat exchanger should be designed based on the starting point of the injection, which requires a lot of phase change energy.

4.2 Energy Saving Method for CO_2 Injection Process

At the conclusion of Section 4.1, the CO_2 transported along the subsea pipeline applied a heating process at the topside of the platform to suppress the instability of the system. However, in the conventional heating process, as the liquid CO_2 was converted into the gaseous CO_2, a large amount of energy had to be supplied due to the latent heat of evaporation. Therefore, a new process that can be applied to offshore platforms has been proposed in this study to reduce the energy consumption of conventional processes. The proposed new process can save the energy of the existing process by using seawater heat source and compressor discharge heat. Numerical comparison of existing heating process and new process and sensitivity study on new process was carried out. As a result, the energy required for the proposed new process was more efficient than the conventional process. The main conclusions from this study are as follows.

(1) The conventional process is a method of converting liquid CO_2, which arrived at the topside, to gas CO_2 through simple heating using a heat exchanger. However, this process is not economical because it requires a lot of energy. Therefore, this study proposed a new process using seawater heat source and compressor discharge heat. The proposed new process can save about 14 ~ 18% energy compared to the existing heating process.

(2) The lower the temperature of discharged seawater in the proposed process, the smaller the energy consumption. However, in order to not affect the surrounding environment, it was assumed that the difference between the temperature of the surrounding seawater and the discharged temperature should be limited to 6 ℃. In addition, the pressure drop of the separator changes the ratio of the energy required for topside facilities. By considering the electric power input to pumps and the compressor, and the heat duty of the heater, the appropriate pressure drop value of the separator should be selected.

본 학위논문은 본인이 석사과정동안 등재한 논문과 연구내용을 바탕으로 작성되었습니다.

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