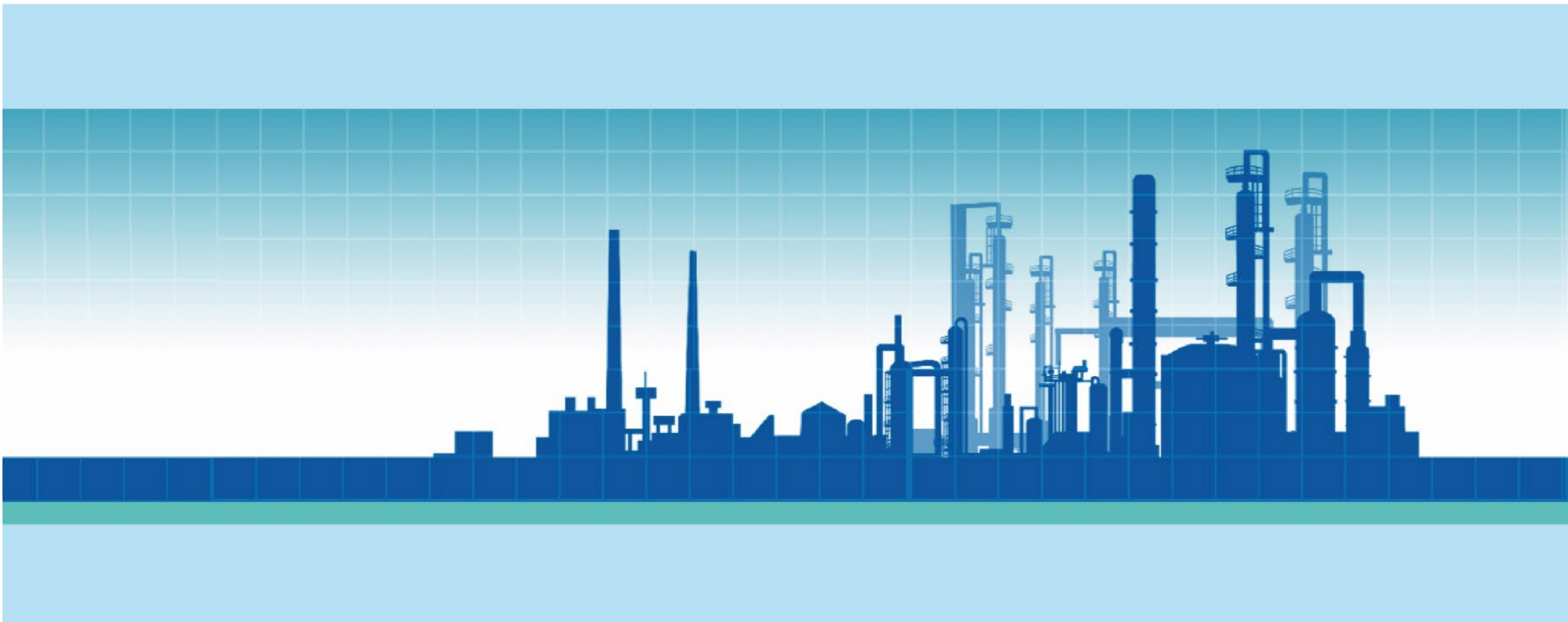
Call ID: LC-SC3-NZE-5-2019-2020

Demonstrating a Refinery-adapted cluster-integrated strategy
to enable full-chain CCUS implementation - REALISE

D 6.3. Synthesis report on full CCUS chain for business case in China

Guojie Qi, Shujuan Wang (Tsinghua University), Davide Bonalumi (POLIMI), Andressa Nakao (NTNU), Matteo Gilardi (SINTEF)



31.10.2023

Dissemination Level (Public)

@realise-ccus | www.realiseccus.eu

Authorisation

This document requires the following approvals:

AUTHORISATION	Name	Signature	Date
WP lead	Hanna Knuutila	Hanna Knuutila	31/10/2023
Project Coordinator	Inna Kim		2023-10-30

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 884266

Disclaimer

The contents of this publication are the sole responsibility of the author(s) and do not necessarily reflect the opinion of the European Union.

Executive summary

REALISE (Demonstrating a Refinery-Adapted Cluster-Integrated Strategy to Enable Full-Chain CCUS Implementation) is a research project funded by the European Union's Horizon 2020 program. It aims to support the decarbonization ambitions of the refinery sector by developing and implementing carbon capture, utilization, and storage (CCUS) technologies.

Tsinghua University in China is an international partner of the REALISE project, contributing to Work Package 6 - Collaboration with Mission Innovation (MI) countries. THU's role includes developing process models for refinery carbon capture process design and and a techno-economic analysis (TEA) method for refinery CCUS economic assessment, evaluating specific refinery CCUS business cases in China, and promoting collaboration between research groups in Europe and China to facilitate large-scale delivery of CCUS technology in the refining sector.

The technical approach involves developing rate-based process models using Aspen Plus to to design and simulate the refinery carbon capture process, using Aspen Process Economic Analyzer and TEA tools developed in Excel to conduct economic evaluaton of the specific refinery carbon capture process. This research project utilizes the IEAGHG carbon capture cost estimation method to perform techno-economic assessments, considering factors and key assumptions to calculate the total plant cost and total capital requirement, in addition to operating costs and key performance indicators, such as CO_2 avoided cost.

This report presents the REALISE CCUS business case for refinery work performed in Task 6.1. It illustrates the procedure followed for the design, optimization, and techno-economic analysis of a CO_2 capture plant for the treatment of the flue gas generated at Jinzhou Refinery near Liaohe Oilfields, located in Liaoning Province, Northeast China.

More specifically, this work deals with:

- An initial evaluation of the feasibility of capturing CO_2 from two refinery's stacks of catalytic cracking units in Workshop #2 of Jinzhou Refinery, contingent upon the impurity composition within the exhaust stream.
- The modeling and optimization of a CO_2 capture facility for the Jinzhou Refinery's flue gas utilizing the Aspen Plus VLE model for the HS3 solvent, as delineated in deliverable D1.3 (Work Package 1). MEA solvent (30 wt.%) has been chosen as a reference for comparative analysis. To this end, analogous simulations have been conducted utilizing AspenTech's default model for 30 wt.% MEA solvent.
- The sizing of the main unit operations in the plant flowsheet as well as the estimation of steam, electricity and cooling water requirements.
- A comparative assessment of HS3's performance relative to the benchmark MEA solvent, encompassing equipment sizing and energy demands.
- The comparison between the economic performances of HS3 solvent with respect to the benchmark MEA solvent in terms of CAPEX, OPEX and CO_2 Avoided Cost.

Overall, the research project provides valuable insights into the potential benefits and challenges of CCUS adoption in refinery processes, paving the way for more efficient and cost-effective carbon capture technologies. Further research is recommended to explore advanced solvents and waste heat integration strategies for better economic performance in refinery

CCUS applications. The research work expresses its appreciation to all partners in the REALISE project, especially Jinzhou Petrochemical Co., LTD., for their valuable knowledge and support in flue gas data acquisition, waste heat distribution, and process evaluation.

Additionally, the financial support provided by the Ministry of Science and Technology (MOST) of China under project No. 2022YFE0197800 was instrumental in the successful completion of this research.

Table of Contents

1 Introduction

1.1 REALISE overview

REALISE – Demonstrating a Refinery-Adapted Cluster-Integrated Strategy to Enable Full-Chain CCUS Implementation

Refineries play a significant role in providing many essential products, from fuels and chemicals to construction materials and consumer goods. However, their operations are associated with substantial carbon dioxide (CO_2) emissions, contributing to the climate change and global sustainability challenges.

To combat this issue, carbon capture, utilization, and storage (CCUS) technologies emerge as a promising solution to effectively enable us to capture and store/utilize CO_2 at multiple point sources in energy-intensive refineries and prevent them from entering the atmosphere. By employing CCUS, the refineries can offset their carbon footprint directly and make these processes even more environmentally friendly, achieve net-zero emissions for a more circular and sustainable economy, and support the ambitious climate policy goals and targets governments and international organizations have set.

The REALISE CCUS project, funded by the European Union's Horizon 2020 programme, unites industry experts and scientists from different nations in a concerted drive to support the refinery sector's decarbonisation ambitions through full CCUS chain development from CO_2 capture, transport and geological CO_2 storage to CO_2 reuse. It is a research project that brings academic and industrial partners in Europe, China, and South Korea to develop and scale up new solvent-based CCUS technologies, evaluate the feasibility of implementing full-chain CCUS at refineries with reduced costs, undertake public engagement and assess financial, political and regulatory barriers, share results and strengthen collaboration with Mission Innovation (MI) countries, like China.

1.2 Task 6.1 CCUS business case for refinery in China

As an international partner of the REALISE CCUS project, Tsinghua University (THU, Beijing, China) has worked with collaborators in Europe and Jinzhou Refinery, China,

- to develop simulation models for refinery CCUS process design and evaluations
- to perform process modelling and techno-economic analysis (TEA) for evaluation of specific refinery CCUS business cases in China for a deeper understanding of refinery CCUS potentials and opportunities in China and
- to promote collaboration between research groups in Europe and China, supporting rapid large-scale implementation of CCUS technology in the refining sector.

The developed simulation models and results will be used for further CCUS project development and implementation in refineries with different complexity and sizes.

In the task, several activities were executed as planned:

- Contribution to outreaching activities in WP4 and dissemination activities in WP5: THU's contribution to outreach activities and dissemination is summarized in D4.5;

- Host EU-China Dissemination event: The hybrid EU-China dissemination workshop was organized by SINTEF, Tsinghua University, and POLIMI on October 11th, 2022 in Cagliary, Italy (Deliverable D6.1);
- Techno-economic assessment of the full-scale capture unit (CAPEX, OPEX) for the China business case at Jinzhou Refinery: The current report describes the technical assessment of the full-scale capture unit using both MEA and HS3 solvent.

However, due to restrictions caused by COVID-19 pandemics, some of the planned activities could not be implemented:

- THU PhD student visit to NTNU for laboratory work was not possible due to travel and lab-use restrictions. Instead, a PhD student exchange from POLIMI to SINTEF was performed within WP1.
- Lab and pilot scale experiments at THU were not possible because the laboratory and pilot plant facilities were out of service during the pandemics. The strict quarantine measures and safety protocols imposed in response to the pandemic made it exceptionally challenging to resume normal operations in a timely manner.

1.3 Chinese refinery activities

As one of the world's largest consumers of petroleum and other refined products, China plays a significant role in the global oil and gas industry. China's refinery industry has undergone remarkable expansion and modernization over the past few decades. In 2018, China's installed crude oil refining capacity reached about 16.8 million barrels per day (Mb/d). In 2021, China's refining capacity came to approximately 18.2 Mb/d. An additional 1.1 Mb/d capacity increase per year was planned to further expand the refining capacity in China. For example, Rongsheng's Phase II refinery and PetroChina's Jieyang refinery both have 0.4 Mb/d capacity, and Shenghong's Lianyungang refinery has a capacity of 0.32 Mb/d [1,2].

The majority of China's refineries were owned and operated by state-owned enterprises like China National Petroleum Corporation (CNPC), Sinopec, and China National Offshore Oil Corporation (CNOOC). However, in recent years, there has been an increasing presence of private and joint venture refineries. In addition, China's refineries have an evident increase in complexity for converting crude oil into a broader range of refined products, such as gasoline, jet fuel, diesel, petrochemicals, and other valuable derivatives. In particular, China's refineries are trying to decarbonize the industry by implementing new technologies, like CCUS, and achieve carbon peak and neutrality targets by 2030 and 2060.

In recent years, China's CCUS technology and demonstration projects have made significant progress. According to a CCUS annual report released by the Ministry of Science and Technology of China, as of the end of 2022, China has nearly a hundred operational and planned CCUS demonstration projects. Over half of the projects are already operational, with a CO_2 capture capacity of approximately 4 million tons per year (Mt/y) and an injection capacity of about 2 Mt/y[3]. These capacities have increased by approximately 33% and 65%, respectively, compared to the figures in 2021.

China's refineries are significant contributors to CO_2 emissions due to the energy-intensive nature of their operations. Integrating CCUS in refineries offers a promising solution to capture and store/utilize these CO_2 emissions, thereby reducing the carbon footprint of the refining industry. Enhance oil recovery (EOR) by injecting CO_2 underground as a primary storage method has been implemented in many oilfields in China, including CNPC's Daqing, Jilin, Xinjiang, and Liaohe oilfields, and Sinopec's Shengli and Zhongyuan oilfields, etc.

Recently, several notable refinery CCUS achievements have been made by major petroleum companies in China. CNPC's Karamay refinery successfully established and operated a CCUS facility in 2016, purifying refinery purge gas and boasting a capacity of 100,000 tons of liquid CO_2 per year (tCO_2/y). Sinopec's Tahe refinery CCUS project processes the purge gas generated from two steam methane reforming (SMR) units, resulting in the production of 116,000 tCO_2/y since 2020. The first million-ton-level Qilu Petrochemical Shengli CCUS project has officially commenced CO_2 injection operations in 2022.

1.4 CCUS perspective in China

China has made remarkable strides in CCUS technology in recent years, enabling the design of large-scale systems for CO_2 capture, pipeline transportation, utilization, and storage. This progress has laid a strong foundation for widespread application in the near future. The construction of CCUS demonstration projects in China has grown rapidly in both number and scale, with various industries adopting CCUS technology, resulting in ongoing reductions in energy consumption costs [3].

The rapid expansion of CCUS demonstration projects is evident in China. By the end of 2022, China has more than 40 projects with capacities of 100,000 tons or more, including over 10 projects exceeding 500,000 tons capacities, and multiple projects with capacities exceeding one million tons are in the planning phase [3]. In August 2022, China's first million-ton CCUS project, the Qilu Petrochemical-Shengli Oilfield project, was completed and put into operation. Other significant projects include Huaneng Group's one-million-ton coal-fired CCUS full-scale demonstration project, the Daqing Oilfield and Jilin Oilfield projects by CNPC, the Xinjiang CCUS industrial cluster jointly planned by CNPC and the Oil and Gas Industry Climate Initiative (OGCI. All of these are poised to make substantial contributions to CO_2 capture and storage efforts, with expectations of reaching millions of tons of capture and storage capacity.

In November 2022, Sinopec signed a memorandum of cooperation with Shell, China Baowu, and BASF to launch China's first open 10-million-ton level CCUS project in East China. This innovative project collects CO_2 from industrial enterprises along the Yangtze River, transports it to a central CO_2 receiving station via trucks, and then to onshore or offshore storage sites through pipelines. This provides integrated CO_2 emission reduction solutions for nearby industrial enterprises. In February 2023, CNOOC, Guangdong Province, Shell China, and ExxonMobil China signed a memorandum of understanding on the Daya Bay Area CCUS Cluster Research Project, which is China's first offshore 10-million-ton level carbon capture and storage industrial cluster.

The CCUS demonstration projects span a wide range of industries, including oil and gas, power generation, chemicals, cement, and steel. Notably, the power generation industry alone has more than 20 demonstration projects. For example, China Energy Group's Taizhou power plant CCUS project, capable of capturing 500,000 tons of CO_2 per year, stands as the largest coal power plant CCUS project in Asia. Industries that are challenging to reduce emissions, such as cement and steel, have also seen a significant increase in CCUS demonstration projects. Baotou Steel Group, for instance, is building a 2 million-ton CCUS demonstration project, set to become the largest CCUS full industry chain demonstration project in the steel sector upon completion.

At present, the CO_2 utilization method of China's CCUS demonstration projects are mainly geological utilization, but chemical and biological utilization projects are also increasing year by year. More than 30 projects carry out CO_2-EOR, a few projects carry out enhanced coal bed methane mining, and only a few projects will ultimately geologically store the CO_2 collected. Tencent Group has announced that it will achieve carbon neutrality by 2030 and is currently cooperating with the Icelandic company Carbfix to plan and build an underground CO_2 rapid mineralization and storage demonstration project.

In terms of chemical utilization of CO_2, the majority of projects are using CO_2 mineralization to prepare building materials such as concrete blocks, while some projects are dedicated to high-value chemicals. The first domestic CO_2 capture and chemical mineralization demonstration project, led by the National Energy Group's Guodian Datong Power Plant, successfully passed a 168-hour trial operation and continuously produced calcium carbonate slurry since 2022. CO_2 bio-utilization projects are on the rise in China, focusing on microalgal cultivation, CO_2 sequestration, and high-value product preparation. In January 2022, Zhejiang University and China Resources Group initiated China's first column-type microalgae photosynthesis reactor project for CO_2 reduction using flue gas from coal-fired power plants. In December 2022, Zhejiang University and Guangdong Energy Group launched a similar project for microalgal cultivation and CO_2 sequestration at Guangdong Yudean Zhanjiang Biomass Power Generation Co.

2 Jinzhou Refinery

2.1 Description

Jinzhou Petrochemical Company, a subsidiary of China National Petroleum Corporation (CNPC), is a fuel and petrochemical refinery established in 1938 and located in Jinzhou, a central city in western Liaoning Province. The company is one of the leading refining and chemical enterprises in China, with the capability to produce National IV, V, and VI standard gasoline and diesel. Its current annual processing capacity is 6.5 million tons, covering the entire production process. Relying on crude oil resources from Daqing and Liaohe oilfields, the company has established a production pattern that spans from crude oil processing to deep refining and comprehensive utilization. This enables the production of 11 categories and 66 grades of petrochemical products, including gasoline, diesel, aviation fuel, needle coke, styrene, isopropanol, butadiene rubber, and additives. Notably, high-quality petroleum needle coke, electronic-grade isopropanol, and rare earth butadiene rubber are key distinctive products that the company emphasizes. The company currently operates 5 large refining workshops, 3 chemical workshops and one combined heat and power (CHP) plant.

2.2 Refinery flue gas characterization

Jinzhou Refinery houses multiple emissions stacks. The company has shared with us flue gas emission data from various sources shown in Table 1 - Table 3, along with the CHP plant. The overall carbon emissions sum up to around 4.35 million tons on a yearly basis. Notably, the CHP plant stands as the largest emission contributor within the refinery, accounting for roughly 2.32 million tons of carbon emissions each year. Among the refinery stacks, catalytic cracking units (CCU) in the Workshop #2, as shown in Table 2, is the primary source of carbon emissions, contributing approximately 1.44 million tons annually.

Table 1- Flue gas data from Jinzhou Refinery

Units	Crude Distillation Unit #1		Crude Distillation Unit #2	
	Atmospheric Distillation	Vacuum Distillation	Atmospheric Distillation	Vacuum Distillation
Temperature [℃]	125	125	124	125
Pressure $[bar]$	1	1	1	1
Flow rate $[Nm^3/h]$	30899	16856	48635	23463
Composition				
CO_2	17.80%	17.80%	12.36%	12.20%
N_2	77.90%	77.50%	79.91%	79.70%
O_2	2.72%	2.28%	6.79%	7.16%
Others	1.58%	2.42%	0.94%	0.94%
Emissions$[ton/year]$				
Subtotal	94640	51628	103437	49255
Total	146267		152692	

Table 2 - Flue gas data from Jinzhou Refinery

Units	Catalytic Reformer Unit #1	Catalytic Reformer Unit #2
Temperature [℃]	59	55
Pressure $[bar]$	1.01	1.01
Flow rate $[Nm^3/h]$	195143	267243
Composition		
CO_2	18.34%	17.94%
N_2	71.72%	70.00%
O_2	5.60%	2.25%
Others	4.34%	9.81%
Emissions$[ton/year]$		
Total	615830	824969

Table 3 - Flue gas data from Jinzhou Refinery

Units	Hydrogen Production - SMR	Coal-fired Plant – 6 Coal-fired Units
Temperature [℃]	145	135
Pressure $[bar]$	1	1
Flow rate $[Nm^3/h]$	28000	900000
Composition		
CO_2	60.00%	15.00%
N_2	30.00%	
O_2	9.00%	
Others	1.00%	85.00%
Emissions$[ton/year]$		
Total	289080	2322964

Jinzhou Refinery has two sets of catalytic cracking units. One of these units employs a parallel riser catalytic cracking design, which underwent capacity expansion and modification in June 2003, resulting in an operational scale of 1 million tons per year. The second catalytic cracking unit features a high-low coaxial parallel design for heavy oil catalytic cracking. Both catalytic cracking units comprise key sections such as reaction-regeneration, distillation, absorption-stabilization, waste heat boiler, main fan assembly, air compressor unit, and low-temperature heat section. The primary focus is on gasoline production, with consideration for liquefied gas yield, while heavy diesel is not produced.

In this project, we have chosen catalytic cracking units as our research focus. The reason for this selection is primarily due to the complex structure of the refinery, characterized by many production units leading to multiple emission stacks. This complexity poses challenges for integrating carbon capture process, as it's difficult to centrally arrange an absorption and regeneration system to achieve comprehensive carbon capture goals across the entire process. In contrast, catalytic cracking units, as a major emission source within the refining process, is relatively centralized in terms of location and contributes to emissions on a scale of millions of tons. Considering these factors, we have chosen catalytic cracking units to conduct process and technical-economic studies. The selected streams to be treated in this study are shown in Table 4.

In light of the space limitations at the refinery, a strategic decision has been made to proceed with the implementation of a singular CO_2 capture plant utilizing an amine solvent. The constrained spatial resources necessitated a thoughtful and practical approach to our emissions reduction efforts. By focusing on a single, highly efficient CO_2 capture system based on amine solvent technology, we can maximize the impact of our environmental initiatives while optimizing the use of available refinery space. This streamlined approach aligns with our commitment to sustainability and responsible resource management, ensuring that we continue to reduce our carbon footprint effectively within the constraints of our operational infrastructure.

Table 4 – Flue gas data for the present study

	Flue Gas #1	Flue Gas #2
Temperature [℃]	59	53
Pressure $[bar]$	1.01	1.01
Flow rate $[Nm^3/h]$	195143	267243
CO_2 concentration (% dry)	18	17.94

Given that catalytic cracking process in the Workshop #2 of Jinzhou Refinery are equipped with two sets of catalytic reformer units generating substantial flue gas emissions, we employed a typical CO_2 absorption/regeneration configuration using one absorber and one stripper for initial feasibility assessment. This assessment will enable us to deeply understand the technical and economic aspects of implementing CCUS technology within the refinery and provide valuable data and outputs of refinery CCUS potential scale-up opportunities in China. Following the progress of this REALISE project, under a fund support from National Key R&D Program of China, THU plans to conduct an on-site visit and assessment of Jinzhou Refinery to gain a deeper understanding of the emission source layout across the refinery and carry out a more extensive and systematic evaluation of the full-scale CCUS process in Jinzhou Refinery, including design, modelling, and technical and economic studies.

2.3 Jinzhou Refinery CO_2 Transportation & Storage Info Search

Jinzhou Refinery, situated within Liaoning Province, China, as depicted in Figure 1, is near Liaohe Oilfield. This proximity highlights the potential of Liaohe Oilfield as a promising site for both CO_2 storage and EOR to support CO_2 capture initiatives at Jinzhou Refinery.

The Liaohe Oilfield, China's largest heavy oil development base, is recognized for its tight sandstone and ultraheavy oil. It annually produces 5.5 million tons of heavy oil. Various enhanced recovery techniques have been utilized, such as steam injection, chemical flooding, nitrogen injection, and CO_2 injection. The typical approach involves using natural gas for boiler combustion to produce water steam, which is then injected into the reservoir. However, the costs associated with conventional steam injection methods have been consistently rising, and their efficacy in enhancing oil recovery is limited. On the other hand, CO_2-based EOR methods, entailing the injection of a mixture of CO_2 and steam into the reservoir at a specific ratio, prove beneficial. This approach helps augment formation energy, extend steam sweep volume, enhance the fluidity of the produced fluid, consequently boosting individual well production. The CO_2 EOR method significantly improves heavy oil sweep efficiency and production rate, resulting in a 12-13% enhancement [4,5].

Estimations by the Liaohe Oilfield Development Division indicate that the developed sector of the Liaohe Oilfield encompasses 292 potential units suitable for implementing CCUS technology, boasting a carbon storage capacity of 530 million tons. Notably, reserves in the likes of the Shuang 229-Block, amenable to utilizing CO_2 for recovery enhancement, reach almost 1 billion tons. The application of CO_2 flooding can elevate oil and gas production by nearly 100 million tons while enabling the storage of 290 million tons of CO_2. Additionally, partially depleted oil and gas reservoirs offer the potential to store an additional 240 million tons of CO_2 [5].

At present, Liaohe Oilfield has regarded CCUS as an important successor area for the future development of the oil field, plans to achieve a carbon capture capacity of 400,000 tons and a utilization and storage scale of 1 million tons by 2025 [6]. In 2021, Liaohe Oilfield carried out a CO_2 storage pilot test in the Ou 37-72-32 well, injecting more than 650 tons of CO_2 and increasing oil by 820 tons. Liaohe Oilfield has put into operation two self-built CO_2 capture and liquefaction stations. It is currently promoting the Shuang 229-Block CCUS-EOR pilot test with a target to inject more than 4 million tons of CO_2 per year and increase the oil recovery rate by 17.5 %.

Liaohe Oilfield Company is a key subsidiary of China National Petroleum Corporation (CNPC). The company's headquarters is located in Panjin City, Liaoning Province. It spans across 12 cities (prefectures) and 32 counties (banners) in Liaoning Province and Inner Mongolia Autonomous Region. Its main operations include oil and gas exploration and development, engineering technology, construction, gas utilization, various business activities, and mining area services. Currently, the company regards CCUS as one of the key technologies that need breakthroughs in the near future, strives to absorb its own carbon emissions, it also conducts intensive research to understand the CO_2 storage needs of surrounding power plants and refineries, like Jinzhou Refinery. The transportation of CO_2 from Jinzhou Refinery to Liaohe Oilfield could be achieved by trucks or pipelines. The distance between Jinzhou Refinery and Liaohe Oilfields (headquarters) is around 102 KM, as it can be seen on Figure 2.

Figure 1- Map of Jinzhou Refinery and Liaohe Oilfield in Liaoning Province, Northeast China

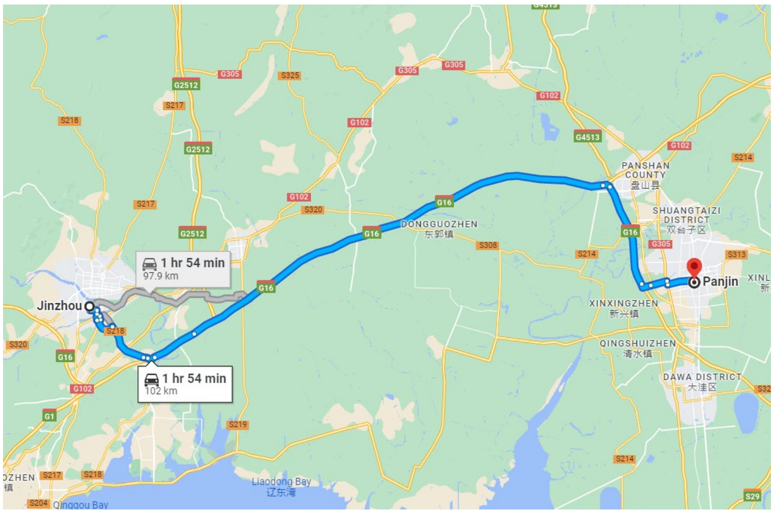


Figure 2- Path between Jinzhou Refinery in Jinzhou City and Liaohe Oilfield in Panjin City

3 Process Design

3.1 Description of the CO_2 capture plant for this study

In this study, the feasibility of CCUS implementation for the two catalytic cracking units, with 1,297,356 tCO_2/year capture capacity, in the Workshop #2 of Jinzhou Refinery was evaluated using developed process simulation and TEA models by Aspen Plus V11, Aspen Process Economic Analyzer (APEA), and Excel. Reference 30 wt.% MEA and HS3 solvents were employed in two difference business cases for calculation and comparisons. This section describes the basic flowsheet for the capture plant, which is based on a conventional solvent-based absorber/stripper configuration for post-combustion carbon capture. A sketch of the flowsheet associated with both studied cases is shown on Figure 3.

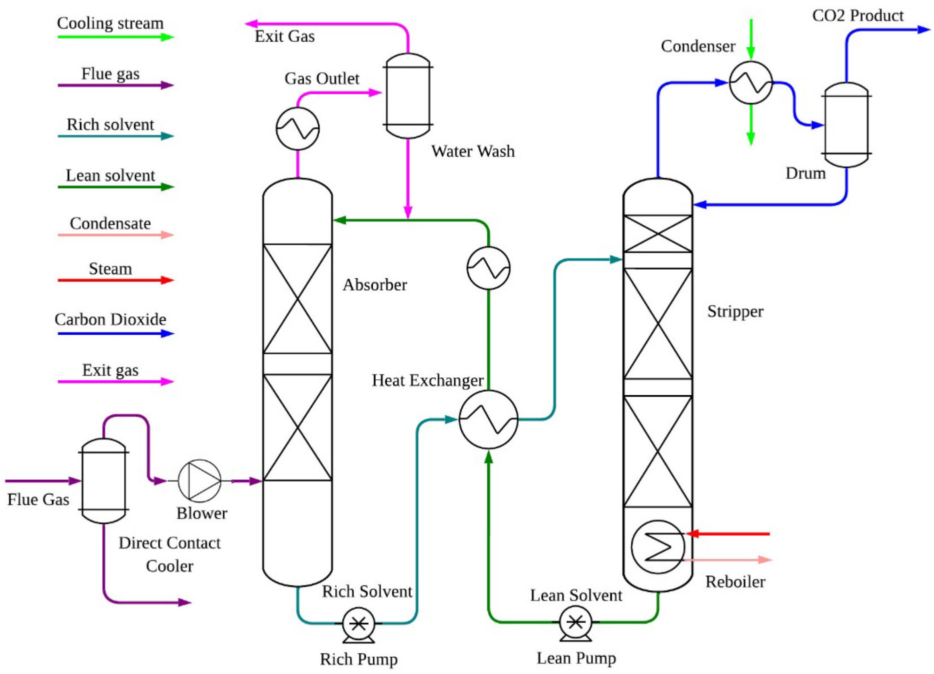


Figure 3- Typical CO_2 absorption/regeneration configuration

The process for solvent-based absorber/stripper configuration employed in this study can be described as follows:

The flue gas is cooled to a specific temperature in a direct contact cooler (DCC). Then, the flue gas passes through a blower to compensate the pressure drop in the DCC and the absorption sub-system (absorber column and the water wash column). Inside the absorber column, the flue gas goes up from the bottom while the solvent goes down from the top in a count-current flow. The solvent will chemically bind with the CO_2 throughout the packing section. The treated flue gas goes through a water wash system before is emitted to the atmosphere. The water wash system is employed to reduce solvent emissions to the atmosphere and helps to maintain the water balance. Per case, possible additional countermeasures need to be evaluated to keep the solvent's emissions below the regulatory limits.

The bottom outlet liquid stream, called rich amine, is pumped to the top of the stripper via a cross-flow heat exchanger. The solvent is regenerated in the stripper at a higher pressure and temperature required to reverse the bond between the solvent and the CO_2. To maintain the regeneration conditions on the stripper, a steam reboiler is used on the bottom to provide the required heat. The energy required on the reboiler is considered the largest contributor to the energy input of the CO_2 absorption-based capture plant. At the top of the stripper, the water content on the outlet vapor stream, rich on CO_2, is recovered using a condenser and a drum, them it is fed back to the stripper.

The lean solvent with residual amounts of CO_2 is pumped back to the absorber via the cross-flow heat exchanger and a cooler to decrease the temperature of it before entering the absorber. On the flowsheet described, there are two loops, the first one is between the absorber and the stripper and it is related with the solvent circulation and the second one is smaller and it is on the water wash section.

3.2 Simulation Environmental

3.2.1 Aspen tools

For the techno-economic assessment, a steady state simulator is needed, for the two proposed cases, it was used the software tools:

- Aspen Plus V11

  Aspen Plus is a widely used process simulation software developed by Aspen Technology, a company known for its comprehensive suite of process engineering and simulation tools. It is designed for engineers and researchers in various industries to model, simulate, and optimize chemical processes, like CCUS process. Aspen Plus helps users design and analyse complex systems, making it a valuable tool for CCUS process design, optimization, and trouble-shooting.

- Aspen Process Economic Analyzer

  Aspen Process Economic Analyzer (APEA), embedded in Aspen Plus, is a software tool also developed by Aspen Technology. This specific software tool is designed to help engineers and professionals in various industries perform economic evaluations and feasibility studies for chemical processes and engineering projects, which is also widely used in CCUS industry. APEA is valuable for estimating project costs, optimizing processes, and making informed decisions related to CCUS process design and investment.

3.2.2 MEA model

The reference case was performed with the benchmark 30 wt.% MEA solvent. Rate-based model built using the RateFrac module, enabled us to accurately calculate mass and heat transfer, reaction kinetics, chemical equilibrium, hydraulic characteristics, and interfacial behaviours of absorber and stripper columns. ENRTL-RK method in the Aspen Plus was applied to describe liquid phase equilibrium behaviour, and Redlich-Kwong-Soave (RKS) equation was used to calculate the vapor phase equilibrium fugacity coefficients.

The reference MEA model provided as an example in Aspen Plus was employed in this study for process modelling and TEA evaluation. The model was widely used in CCUS literature, which can accurately simulate the property, thermodynamics, kinetics, and MEA based carbon capture process. As the flue gas compositions of Jinzhou Refinery were very similar with the reference MEA model in Aspen Plus, model validation was not carried out in this study. Further validation work will be conducted by comparing real refinery CCUS experimental data and simulation results in the future.

3.2.3 HS3 model

On REALISE CCUS project, it was developed a HS3 thermodynamic model for Aspen by POLIMI, called Aspen Plus VLE model, which was validated with Tiller pilot data campaign. This model was used for the present case study. The detailed introduction about HS3 model can be found in deliverable D1.3 [7] of Work Package 1 in the REALISE CCUS project.

3.3 Specifications of the unit operations

The flowsheets for both MEA and HS3 processes exhibit a high degree of similarity to assure consistency and promote a better comparison between the two solvents, reflecting a common foundation in their design. However, the choice of solvent is a key factor for the process. Since distinct solvents are employed in each process, some units required unique specifications and adjustments to make them work effectively. While the core framework remains consistent, these adjustments ensure that each process can achieve the desired capture rate. The fitting of unit specifications for each process allows us to optimize capture in a manner that aligns with the characteristics of the chosen solvents, contributing to the overall convergence of the respective processes. The carbon capture plant model for the MEA solvent developed for the present work is shown on Figure 4. The specifications for the process unit operations necessary for the simulations and for the cost estimation will be listed below.

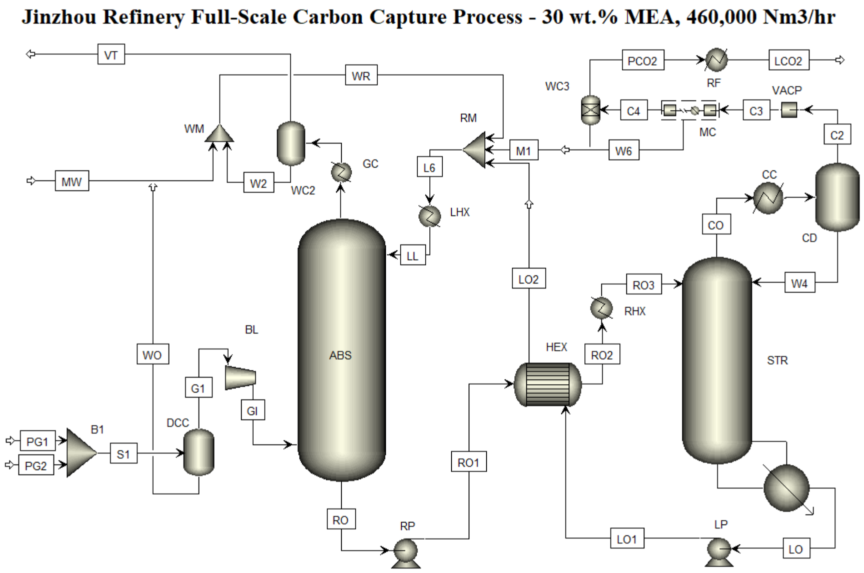


Figure 4 - Jinzhou Refinery MEA solvent carbon capture process modeling using Aspen Plus

3.3.1 Columns

The flowsheet consists of four columns: absorber, stripper, water wash, and direct contact cooler (DCC). In both simulations, the absorber and stripper were set up as columns, while different approaches were used for the water wash and the direct contact cooler. The specifications for these four units can be found in Table 5 and Table 6, for the MEA and HS3 solvent, respectively.

The precooled flue gas undergoes an additional cooling stage within a direct contact cooler (DCC). For the HS3 model, it was assumed that the cooling water circuit supplies water at an initial temperature of 20 °C, the process water circulating through the DCC loop can be expected to reach a temperature of 25 °C. Moreover, a temperature approach of 3 °C within the DCC system was set, ensuring that the flue gas exits the upper part of the DCC at a temperature of 28 °C. For the MEA model, the flash model in Aspen Plus was adopted as a DCC to lower the incoming flue gas temperature from 56-59 °C to 20 °C. The heat duty of DCC was calculated for potential flue gas waste heat recovery from the refinery. The waste heat integration was not included in this report and will be studied in the following project.

CO_2 removal occurs within an absorber (ABS), which is a packed column. Flexipac 250Y (Koch) packing was used for the MEA case, and Mellapak 250x (Sulzer) for the HS3 case. The required solvent flow into the ABS is determined to enable the removal of 90% of the incoming CO_2 within the column. The interactive sizing tool, available in Aspen Plus V11, is utilized to estimate the design diameter for both the absorber and the stripper. In this sizing process, the design is based on the flooding velocity, which necessitates temporarily switching from rate-based to equilibrium calculations using a Calculations Type switch in Aspen Plus. This temporary shift in calculation mode allows for accurate sizing using the tool. After the sizing is complete, the simulation reverts to rate-based mode, which is essential for properly addressing mass-transfer limitations within the system.

Also, the stripper is modelled as a rate-based unit, but kinetics is disregarded since it is based on experimental data collected at much lower temperatures (25-40 °C) with respect to the ones observed inside this column. This assumption is often adopted since desorption reactions are fast enough so that mass transfer becomes the limiting step [8]. The column has one degree of freedom, which is saturated by imposing that the regenerated solvent must have a lean loading equal to the one of the initial solvent fed to the absorber. This specification allows the closing of the CO_2 mass balance and it considerably speeds up the convergence of the unit with respect to alternative specifications, such as the bottom temperature, especially while working with the HS3 model.

For the HS3 CO_2 capture plant model, the water-wash column is designed to have the same diameter as the absorber column. The packing height for the water-wash column is chosen to meet the specified residual amine content in the treated gas. This height is determined by using a circulating water rate that ensures the washing section does not exceed 70% of the flooding velocity. To minimize water consumption, a closed-loop system is employed, eliminating the necessity for continuous integration of significant amounts of fresh water into the plant. For the MEA case, the water-wash column was simulated using a flash model in Aspen Plus to mainly evaluate the impact of temperature on MEA emission control. The water-wash column collects water vapor from the exhausted gas on top of the absorber at 20 °C, which can remove all the MEA slip in this simulation.

Table 5 - Specifications for the columns in MEA Case

Column	Absorber	Stripper	Water-Wash	Direct Contact Cooler
Parameter	Value/spec			
Model type	Packed Radfrac	Packed Radfrac	Flash	Flash
Operating velocity*	80% flooding	80% flooding	-	-
Capture level (% incoming CO_2 content)	90	-	-	-
Packing type	FLEXIPAC 250Y (Koch)	FLEXIPAC 250Y (Koch	-	-
Packing diameter $[m]$	11.5	7		
Packing height $[m]$	12	12	-	-
Liquid temperature inlet [°C]	40	105	20	20
Calculation type	Rate-based method	Rate-based method	Vapor-liquid flash	Vapor-liquid flash
Pressure drop	0.04	0.1	-	-

*This parameter was used for the column diameter calculation

Table 6 - Specifications for the columns in HS3 Case

Column	Absorber	Stripper	Water-Wash	Direct Contact Cooler
Parameter	Value/spec			
Model type	Packed Radfrac	Packed Radfrac	Packed Radfrac	Packed Radfrac
Operating velocity*	70% flooding	70% flooding	-	-
Capture level (% incoming CO_2 content)	90	-	-	-
Packing type	Mellapak 250x (Sulzer)	Mellapak 250x (Sulzer)	-	-
Packing diameter $[m]$	10	6.1	6.5	8
Packing height $[m]$	18	14	7	3
Liquid temperature inlet [°C]	43	107.5	20	20
Calculation type	Rate-based method	Rate-based method	Rate-based method	Rate-based method
Pressure drop	0.06	0.1	0.03	0.03

3.3.2 Heat exchangers

On both cases, the heat exchangers situated at the top of the absorber and stripper function as lean amine cooler, as well as condenser acts as a cooling unit, they were modelled using a heater/cooler model in Aspen Plus. Meanwhile, the lean-rich cross heat exchanger was implemented as a heat exchange unit and modelled using a HeatX model in Aspen Plus. We utilize cooling water entering at 20 °C and exiting at 35 °C as a utility.

In the MEA scenario, the specification for the reboiler focused on the reboiler duty, varying it according to the mass balance of lean and rich CO_2 loading.

The specifications of heat exchangers for the MEA case and HS3 case can be found on Table 7 and Table 8, respectively.

Table 7 – Specifications for the heat exchanger in MEA case

Parameter	value
General Cooler and Stripper condenser	
Temperature of outlet process side [°C]	30
Pressure drop (gas)	0.1
Lean Cooler	
Temperature of outlet [°C]	40
Lean/rich Amine heat exchanger	
Temperature approach [°C]	10
Reboiler	
Operating tempertaure [°C]	119

Table 8 - Specifications for the heat exchangers in HS3 case

Parameter	value
General Cooler and Stripper condenser	
Temperature of outlet process side [°C]	30
Pressure drop (gas)	0.1
Lean Cooler	
Temperature of outlet [°C]	44
Lean/rich Amine heat exchanger	
Temperature approach [°C]	10
Reboiler	
Operating temperature [°C]	119

3.3.3 Pumps and fan

Pumps will be required in different places in the capture plant. The required pressure differences are quite small and in general all of them are not included in the simulations. The pumps included on the simulation are rich pump, lean pump, a pump for water circulation inside the DCC and WW loops. It is assumed that pumps are located on the ground.

The rich solvent is pressurized using the rich pump to achieve the necessary operating pressure for the stripper while also compensating for pressure losses in the lean-rich heat recovery exchanger and the pressure required to feed the solvent to the upper stage of the stripper. To accomplish this, a pressure drop of 0.35 bar in the lean-rich exchanger is set in accordance with guidelines recommended by Seider et al. [9]. Additionally, an elevation-based pressure drop of 1 bar per 10 meters of vertical ascent is considered. Furthermore, a temperature approach of 10 °C is enforced as a specific requirement within the lean-rich exchanger.

The regenerated solvent is pumped by the lean pump to guarantee a sufficient pressure to overcome the elevation gain to reach the top of the absorber, and it is further cooled in lean amine cooler and recycled back to the absorber.

A fan performs an important role in overcoming the total pressure drops within the Direct Contact Cooler, the absorber, and the water-wash columns. Given that the complexity of the absorption column surpasses that of the packing, the pressure drops, as estimated by the process simulator using rate-based modeling techniques, are doubled for conservative estimation. This accounts not only for the specified packing height but also for potential additional pressure losses attributed to factors such as injection systems, effective column height, and the possibility of multiple packing beds. The fan's efficiency is modeled at 80%. The total pressure drop to be addressed is also influenced by the total absorber packing height, falling within the range of 0.2 to 0.23 bar, depending on the specific circumstances.

The pumps and fan specifications can be found summarized on Table 9 and Table 10 for MEA case and HS3 case respectively.

Table 9 – Pumps and fan specifications for MEA case

Parameter	Value
Pump	
Hydraulic efficiency	0.8
Driver efficiency	0.95
Fan	
Hydraulic efficiency	0.8
Driver efficiency	0.95

Table 10 - Pumps and fan specifications for HS3 case

Parameter	Value
Pump	
Hydraulic efficiency	0.8
Driver efficiency	0.95
Fan	
Hydraulic efficiency	0.8
Driver efficiency	0.95

3.3.4 Utilities

As mentioned before, the available cooling water is at an inlet temperature of 20 °C. For amine solvent regeneration it was used low pressure steam as heat source. The utilities specifications can be found summarized on Table 11 and Table 12.

Table 11 – Utilities specifications for MEA case

Utility	Inlet temperature [℃]	Outlet temperature[℃]
Water cooling	20	35
Steam	130	130

Table 12 – Utilities specifications for HS3 case

Utility	Inlet temperature [℃]	Outlet temperature[℃]
Water cooling	20	35
Steam	130	130

4 Simulations Results

4.1 Reference Case: 30 wt.% MEA as solvent

The characterization of the reference MEA-based carbon capture plant is obtained simulating it with Aspen Plus V11. The main streams characterization is proposed in Table 12.

Table 13 – Characterization of the main streams: temperature, pressure, phase, mass and molar flows

Stream From-to	Fan-Absorber (GI)	Absorber WW (GO)	WW-outside (VT)	absorber-rich pump (RO)	Rich-lean cross exchanger-striper (RO3)	Reboiler - lean pump (Lo)	Stripper condenser-outside (C2)
Temperature [°C]	32.2	65.1	20.0	50.1	105.0	120.3	30.0
Pressure [bar]	1.14	1.1	1.05	1.14	2	2	1.9
Mass flow [ton/h]	608	530	461	3137	3137	2987	149.5
Mole flow [kmol/h]	20641	21132	17335	124372	124959	124291	3447

The duties of the plant including steam, electricity and cooling water are summarized in Table 13.

Table 14 – Summary of the main duties (in MW) of the MEA-based CO_2 capture plant.

Equipment	**Utility**	**Duty [MW]**
Reboiler	Steam	162
Fan (BL)	Electricity	2.26
Rich Pump (RP)	Electricity	0.18
Lean Pump (LP)	Electricity	0.09
Lean amine Cooler (LHX)	Cooling water	133
Stripper Condenser (CD)	Cooling water	55
DCC Cooler (DCC)	Cooling water	6.49
WW Cooler (GC)	Cooling water	56

Steam and cooling water are associated to the higher duties. The most impactful utility cost is the one associated to steam. Which is 163 MW consumption for the MEA-based capture plant. The specific reboiler duty (SRD) was calculated based on reboiler duty and CO2 capture rate, as shown in Table.

Table 15 – Total and specific duty, capture rate and total captured CO_2

Reboiler duty [MW]	161.895
SRD [MJ/kg CO_2]	3.935
Total captured CO_2 [ton/year]	1297356
CO_2 capture rate [%]	90.0

The specific reboiler duty is 3.935 MJ/kg CO_2, which is relatively high and very close to regeneration energy requirements of MEA solvent published in literature. The calculated reboiler duty in this study indicates that the MEA case is a good reference for comparison with the HS3 solvent.

In terms of electricity consumption, the fan plays a crucial role, representing around 90% of the total power requirements. This can be attributed to the substantial pressure drops experienced on the flue gas side, which are further amplified by the specific plant configuration in use.

4.2 Study case: HS3 solvent

The characterization of the carbon capture plant is obtained simulating it with Aspen Plus V11. The main streams characterization is proposed in Table 15.

Table 16 Characterization of the main streams: temperature, pressure, phase, mass and molar flows

Stream From-to	Fan-Absorber	Absorber WW	WW-outside	absorber-rich pump	Rich-lean cross exchanger-striper	Reboiler - lean pump	Stripper condenser-outside
Temperature [°C]	52	75.8	60.7	48.2	107.5	122.0	30
Pressure [bar]	1.12	1.10	1.05	1.12	4.95	1.8	1.7
Mass flow [ton/h]	608	547.86	517.2	2064.4	2064.4	1914.7	149.7
Mole flow [kmol/h]	20641	21050	19516	55486	55491	55403	3451

The duties of the plant including steam, electricity and cooling water are summarized in Table 16

Table 17. Summary of the main duties (in MW) of the HS3-based CO2 capture plant.

Equipment	**Utility**	**Duty [MW]**
Reboiler	Steam	120
Fan (C-1)	Electricity	4.16
Rich Pump (P-1)	Electricity	0.18
Lean Pump (P-2)	Electricity	0.14
DCC water Pump (P-3)	Electricity	0.07
WW water Pump (P-4)	Electricity	0.04
Lean amine Cooler (E-1)	Cooling water	49
Stripper Condenser (E-2)	Cooling water	19
DCC Cooler (E-4)	Cooling water	14
WW Cooler (E-5)	Cooling water	22

Steam and cooling water are associated to the higher duties. The most impactful utility cost is the one associated to steam, see Table 17.

Table 18 Total and specific duty, capture rate and total captured CO_2

Reboiler duty [MW]	120
SRD [MJ/kg CO_2]	2.9
Total captured CO_2 [ton/year]	1298109
CO_2 capture rate [%]	90.2

The specific reboiler duty is 2.9 MJ/kg CO_2. In other words, considering that steam is supposed to be available at saturation conditions at 130 °C.

Regarding electricity consumption, the fan holds a key role, accounting for approximately 90% of the total electricity demands. This result is justifiable due to the significant pressure drops experienced on the flue gas side, a contribution further accentuated by the specific configuration employed in this plant.

Despite the substantial cooling requirements of the facility, cooling water management poses a lesser concern due to its cost-effectiveness. The primary utilization of cooling water takes place within the DCC and WW loops, as well as in the cooling of the lean stream before its introduction into the absorber.

4.3 Preliminary discussions

The simulations revealed that the HS3 solvent exhibited a 19% decrease in L/G (liquid-to-gas ratio), and a 26% lower reboiler duty compared to the MEA solvent.

The findings align with those documented in Deliverables 2.4 and 3.2, illustrating the diminished reboiler duty observed with the use of the HS3 solvent when comparing with the MEA solvent. It is crucial to emphasize that the variations in the percentage reduction between these studies stem from the differing operational conditions and specific assumptions incorporated during the simulation process.

5 Economic assessment

5.1 Criteria and Assumptions

Given the importance of cost estimation in CCUS technologies, several organizations have dedicated efforts to create procedures, guidelines, and tools for assessing the techno-economic performance of CCUS processes. Notable organizations involved in this endeavour include the International Energy Agency Greenhouse Gas Programme [10], the U.S. Department of Energy's National Energy Technology Laboratory [11], the Electric Power Research Institute (EPRI), and the Global CCS Institute [12].

The research project selected the IEAGHG cost estimation method to assess the techno-economic aspects of refinery carbon capture processes due to its user-friendly nature, wide availability, and extensive adoption by organizations worldwide, particularly in the field of refinery CCUS. For instance, the ReCap project, funded by CLIMIT, conducted a comprehensive TEA study on refinery cases using this method [13]. This method considers a wide range of factors and key assumptions to calculate the total plant cost (TPC) and total capital requirement (TCR), in addition to operating costs and key performance indicators (KPIs). Given its extensive coverage in existing literature, we refrain from providing a detailed introduction to it here.

Figure 5 illustrates the cost estimate method framework for a refinery carbon capture plant. The Aspen Process Economic Analyzer (APEA) V11 (with a 2018 pricing basis), was utilized to calculate the primary equipment costs associated with the refinery carbon capture scenarios. The total investment cost percentages used in the calculations followed the guidelines outlined by the IEAGHG TEA practice.

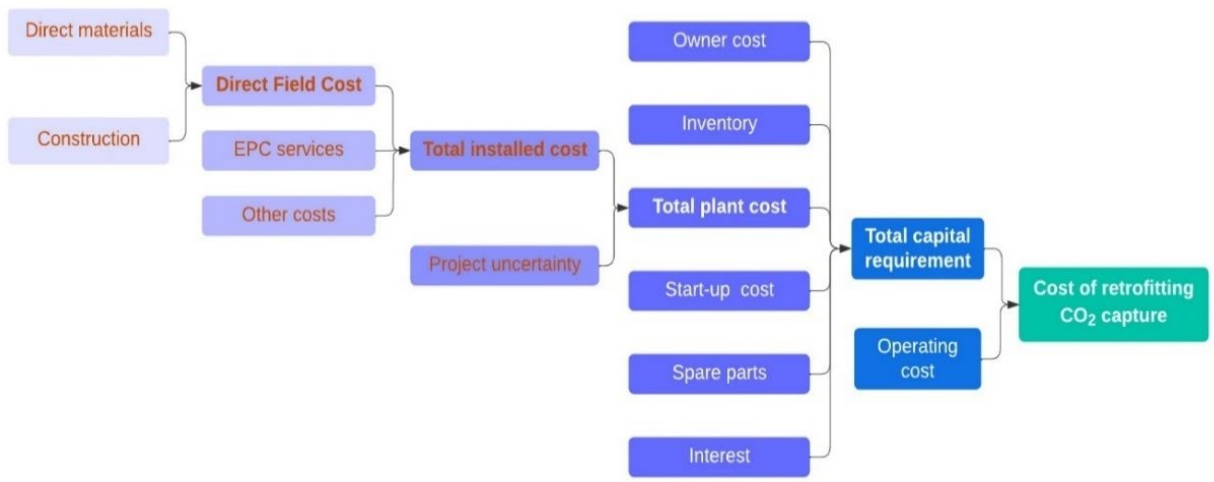


Figure 5 - Cost Estimate Method Framework for a Refinery Carbon Capture Plant

Unlike power station CCUS cases, the cost of the refinery CO_2 capture process is determined by the additional CCUS expenses incurred by a specific refinery without affecting its production. It is calculated as the sum of the annualized capital expenses (CAPEX) and the annual operating cost (OPEX), divided by the annual amount of CO_2 avoided, as shown in Equation 1.

Equation 1

$$Cost_{CO_2\ avoided} = \frac{Annualized\ CAPEX + Annual\ OPEX}{Annual\ amount\ of\ CO_2\ avoided}$$

The annualized CAPEX is determined by utilizing the total capital requirement (TCR) over a 25-year economic project lifespan and applying an 8% discount rate, amounting to 8.67% of the TCR. The Annual OPEX, on the other hand, is determined by combining fixed operating and maintenance costs with variable operating and maintenance costs. The capture plant operates for 8,400 hours annually, achieving an average utilization rate of 95.9%. The annual quantity of CO_2 avoided is calculated using the CO_2 capture rate of the Jinzhou refinery capture plant (148 tons per hour) and the annual utilization rate of the capture plant, resulting in an annual reduction of 1.24 million tons of CO_2 per year.

It is assumed that the CO_2 capture plant is situated in the vicinity of Workshop #2 at the Jinzhou Refinery. This site requires no significant site preparation, and there are no special civil works or limitations related to the delivery of equipment. There are existing rail lines, roads, fresh water supply, high voltage electricity transmission lines, and a high-pressure natural gas pipeline available for use at the capture plant.

All costs are presented in 2018 US dollars, as per the economic results output from Aspen Plus V11. Any necessary cost updates can be carried out using the Chemical Engineering Plant Cost Index (CEPCI), although such updates are not included in this report. Inflation rates and depreciation are not factored into this study. The design and construction period is assumed to be 3 years.

5.2 Equipment selection and capital cost

The capital cost of the CO_2 capture plant is expressed as the total capital requirement (TCR), encompassing the total plant cost (TPC), spare parts cost, start-up costs, owner's expenses, interest incurred during construction, and working capital. In both business cases in this study, the TPC is calculated by considering a combination of factors such as direct materials cost, construction cost, EPC services cost, contingency expenses, and other essential costs. These calculations take into account the specific characteristics and design conditions of each piece of equipment within the capture plant.

The remaining components of the TCR are primarily estimated as percentages of the TPC of the capture plant, following standard IEAGHG practices. The spare parts cost is assumed to be 0.5% of TPC, while start-up costs comprise equipment modification expenses (2% of TPC), owner's expenses (7% of TPC), 25% of the full capacity fuel cost for one month, three months of operating and maintenance labour costs, and one month of chemicals and waste disposal costs.

The TPC estimates are derived from the results of process modelling, as illustrated in Figure 4, and equipment costs obtained from Aspen Process Economic Analyzer (APEA) V11. The equipment discussed in Chapter 3 is included in the estimation of equipment costs. For determining the overall column height of both the absorber and stripper in both business cases, good practices for design recommended by van der Spek et al (2019) [15] and Kvamdsal et al (2010) [14] were employed.

The specifications and costs of pumps and heat exchangers within the capture plant were determined using Aspen Plus and APEA. However, it's important to note that this study did not involve a detailed equipment selection process. Kettle-type reboilers were utilized for CO_2 regeneration, while plate and frame type heat exchangers were employed for the lean amine cooler, rich/lean heat exchanger, and condensers. Detailed material selection is not provided in this study, but it is assumed that stainless steel is used for all the equipment to handle the various operations.

5.3 Equipment cost estimation method

For the HS3 case study, the equipment cost estimation was calculated based on the equipment sizing from the reference case by using a power law with corresponding cost exponents shown on Equation 2.

Equation 2

$$Cost_{HS3} = Cost_{MEA}\left(\frac{Vol_{HS3}}{Vol_{MEA}}\right)^{0.6}$$

Where the parameter Vol stands for the characteristic dimension of the equipment, in other words:

- the volume for the columns (absorber, DCC, water-wash and stripper);
- the area for heat exchangers;
- the duty for pumps and for the fan.

The values used for the parameter Vol is shown on Table 19. The values were calculated based on the data from REALISE Deliverable 3.2 and the following assumptions:

- The heat exchanger, pumps Vol_{HS3} was estimated based that HS3 has 24% lower solvent flow rate
- The volume of absorber and stripper were based on the geometric parameter values given by process modeling results in Aspen Plus for both MEA and HS3 cases, as shown in Table 5 and Table 6.
- The compression and the pre-treated section were considered the same for MEA.

Table 19 – values for the parameter Vol for Equation 2

Abbreviation	Equipment description	Vol_{MEA}	Vol_{HS3}
RHX	Rich heat exchanger	1	0,76
WC3	CO2 conpression cooler	1	1
B1	Flue gas mixer	1	1
MC	Multi-stage compressor	1	1
GC	water-wash cooler	1	1
CC	Condenser cooler	1	1
BL	Blower	1	1
RP	Rich pump	1	0,76
DCC	Direct contact cooler	1	1
HEX	Lean/rich heat exchanger	1	0,76
ABS	Absorber	1246.39	1413.68
LP	Lean pump	1	0,76
CD	Condenser (top stripper)	1	1
RF	CO_2 refrigerator	1	
LHX	Lean cooler	1	0,76
WM	Water mixer	1	1
STR	stripper	461.80	409.13
RM	Returned solvent mixer	1	1
WC2	Water wash	1	1

5.4 Operational costs

Operational expenses associated with the CO_2 capture facility can be categorized into two main categories: fixed and variable operating costs. Fixed operating costs represent expenditures that remain constant irrespective of the plant's operational level or production output, including direct labour cost, administrative and general overhead cost, annual operating and maintenance cost, insurance, local taxes and fees. Even if the plant reduces its production activities, these costs remain unchanged.

Labor costs include operating labour, administrative staff, and support labour, calculated based on the total number of employees and an annual average salary of $30,000 per year. The number of personnel engaged is estimated for each case, considering a 5-shift work pattern with a total of 40 employees. Maintenance costs include preventive maintenance and corrective maintenance expenses, covering repair and replacement of failed components. In this study, annual maintenance costs are estimated as a percentage of TPC (total plant cost) for various components and systems: flue gas treatment (2.0% of TPC), CO_2 capture and conditioning (2.0% of TPC), power plant (2.5% of TPC), cooling tower and wastewater treatment (1.0% of TPC), and interconnection (1.0% of TPC). The total cost for insurance, local taxes, and fees is calculated to be 0.5% of the total plant cost (TPC).

Variable operating costs refer to expenses that fluctuate with the level of production or operational activity within a business. These costs are directly related to the volume of output and include expenses such as natural gas consumption, MEA/ HS3 solvent cost, raw process water make-up cost, solvent sludge disposal cost, and other related chemical cost. Variable costs increase as production or activity levels rise and decrease as they fall.

It is worth noting that the cost of CO_2 avoidance is highly sensitive to the prices of the solvents used. In this study, two solvents, MEA and HS3, were employed, and their respective prices in China are presented in Table 20. These prices were obtained from an industrial chemical purchasing website. Specifically, the price for MEA is $2,000 per ton, while the price for HS3 is $4,420 per ton. Thus, HS3 is approximately 2.2 times more expensive than MEA in China.

Table 20– Price of the MEA and HS3 solvents

Consumable	Price	Cost unit
MEA solvent	$2,000/ton	$/ton
HS3 solvent	$4,420/ton	$/ton

5.5 Results

5.5.1 Equipment investment cost

The IEAGHG carbon capture cost estimation method was used for a comprehensive cost assessment of the Jinzhou Refinery capture plant, categorizing the estimates into three sections: capture and compression, utilities, and interconnections, as shown on Table 21 and Table 22. The capture and compression section evaluated the costs of absorption, regeneration, and CO_2 compression, show on Table 20. More detailed cost by equipment can be found on Table 20.

The utilities section considered the CHP plant (responsible for providing steam and power), cooling towers, and wastewater treatment costs. The interconnections section assessed refinery retrofitting costs for carbon capture implementation, including expenses for piping, ducting, and other infrastructure modifications to integrate the carbon capture facility into the existing refinery setup. The overall cost breakdown, key performance indicators are then evaluated for the Jinzhou Refinery case based on the built excel model for assessing the feasibility of purge gas CO_2 capture from refineries.

Using the Aspen Plus model and the Aspen Process Economic Analyzer, detailed equipment list was built for the CO_2 capture and compression section, including key characteristics of each equipment. Direct material costs, direct field costs, and total installed cost were estimated for calculating the total capital requirement. For the utilities and interconnecting section, the total installed cost and total capital requirement were estimated based on factors and key assumptions from the IEAGHG cost estimation method. Operating costs were calculated considering the expenses of employment, utility and mass balances, and plant performance.

Table 20 – Equipment investment cost for each case of study

Name	MEA Equipment Cost [USD]	HS3 Equipment Cost [USD]	Comparison
RHX	$38 100,00	$32 315,67	-17,90 %
WC3	$20 100,00	$20 100,00	0,00 %
B1	\	\	
MC	$1 266 600,00	$1 266 600,00	0,00 %
GC	$22 300,00	$22 300,00	0,00 %
CC	$16 500,00	$16 500,00	0,00 %
BL	$1 414 100,00	$1 414 100,00	0,00 %
RP	$16 000,00	$13 570,88	-17,90 %
DCC	$26 400,00	$26 400,00	0,00 %
HEX	$371 000,00	$314 674,87	-17,90 %
ABS	$2 257 800,00	$2 435 021,59	+7,28 %
LP	$13 200,00	$11 195,98	-17,90 %
CD	$18 900,00	$18 900,00	0,00 %
RF	$29 100,00	$29 100,00	0,00 %
LHX	$63 100,00	$53 520,17	-17,90 %
WM	$0,00	$0,00	
STR	$3 683 400,00	$3 425 272,37	-7,54 %
RM	$0,00	$0,00	
WC2	$18 900,00	$18 900,00	0,00 %
VACP	$544 000,00	$544 000,00	0,00 %
Total [10^3USD]	$9 819,50	$9662,50	

The outcome from the equipment cost is as anticipated. In accordance with the outputs from the studies elaborated on REALISE CCUS WP1, WP2, and WP3, it is evident that HS3 solvent demonstrates slower kinetics and necessitates a greater packing height, leading to an increased cost of purchasing the absorber.

Regarding the benefits of utilizing the HS3 solvent, it was highlighted that it requires a lower solvent flow rate and entails a smaller reboiler duty, consequently reducing the necessity for extensive heat exchanger surfaces and lowering the overall heat exchangers purchase cost.

Table 21 – Costs in absorption, regeneration and compression sections

	MEA Equipment Cost [1000 USD]	HS3 Equipment Cost [1000 USD]
Absorption	3815,8	3981.4
Regeneration	4143,9	3821.2
Compression	1859,8	1859,8
Total	9819,5	9662,5

5.5.2 Total plant cost estimation

The cost of retrofitting CO_2 capture (CO_2 avoided cost) obtained by summing the annualized capital expenses (CAPEX) and the annual operating costs (OPEX) and dividing the result by the annual amount of CO_2 avoided.

As shown in Table 22, the CO_2 avoided costs in the capture and compression utilities, and interconnections sections were 8.8, 39.8, and 14.5 $/tCO_2$The total CO_2 avoided cost was 63.1 $/tCO_2$, which is relatively high if compared to estimates available in the literature on carbon capture for power plant. The reasons might be interconnection costs were included for calculation, the utilities section has high steam cost because assumption of an additional CHP plant installation for carbon capture was made, limited data available for the actual Jinzhou refinery, causes potentially large overestimates with large spare capacity.

Table 22 - TEA Results of Jinzhou Carbon Capture Case Study Reference Case Study

Cost Categories	CO_2 Avoided Cost ($/tCO_2$, avoided)
Capture and Compression (CC)	8.8
CAPEX	2.1
Fixed OPEX	1.4
Variable OPEX	5.4
Utilities (U)	39.8
CAPEX	1.3
Fixed OPEX	0.6
Steam Cost	37.6
Other Variable OPEX	0.3
Revenues*	0.0
Interconnections (I)	14.5
CAPEX	12.1
Fixed OPEX	2.4
Variable OPEX	0.0
Total Cost	63.1

* Notes: CO_2 sales, carbon credit, etc., not included.

As shown in Table 26, the CO_2 avoided costs in the capture and compression utilities, and interconnections sections were 13.8, 31.8, and 14.6 $/tCO_2$.The total CO_2 avoided cost was 60.2 $/tCO_2$, which is relatively high if compared to estimates available in the literature on carbon capture for power plant.

Table 23 - TEA Results of Jinzhou Carbon Capture Case Study HS3 Case Study

Cost Categories	CO2 Avoided Cost ($/tCO2, avoided)
Capture and Compression (CC)	13.8
CAPEX	2.1
Fixed OPEX	1.3
Variable OPEX	10.4
Utilities (U)	31.8
CAPEX	1.3
Fixed OPEX	0.5
Steam Cost	29.7
Other Variable OPEX	0.3
Revenues*	0.0
Interconnections (I)	14.6
CAPEX	12.1
Fixed OPEX	2.5
Variable OPEX	0.0
Total Cost	60.2

6 Conclusions

This document outlines the process undertaken to develop an efficiently CO_2 capture facility for the catalytic cracking units at the Jinzhou Refinery, responsible for 1.44 MT CO_2 emission per year. The design involved the utilization of the HS3 solvent and MEA 30 wt.% solvent. Adhering to the project requirements, a comprehensive techno-economic assessment (TEA) was conducted, alongside a thorough overview of a complete CCUS (Carbon Capture, Utilization, and Storage) chain for the specific refinery in question.

It is essential to emphasize that while the initial task proposal involved an analysis of multiple CO_2 sources, a prior study was conducted regarding the available space within the refinery for the potential implementation of a CO_2 capture plant. This study concluded that only the catalytic cracking unit area was suitable for this purpose.

The modelling tool employed was the HS3 model developed in Aspen Plus V11.0 within WP1 and documented in D1.3. To enable a performance comparison with a benchmark, parallel simulations were conducted using the default MEA 30wt.% model offered by AspenTech.

The simulations indicated that the HS3 solvent demonstrated a 19% reduction in the L/G (liquid-to-gas) ratio and a 26% decrease in reboiler duty compared to the MEA solvent. As mentioned earlier, this outcome is consistent with the findings from the studies conducted during the REALISE CCUS project.

This study was conducted in a Chinese refinery, and China is significant producer of the main component of the HS3 solvent. This factor significantly impacted the operational cost calculation in the study. Some of the cost estimates for this analysis were obtained from assumptions made based on Chinese purchasing websites, directly influencing the overall cost, and contributing to a more suitable scenario for implementing a CO_2 capture plant using HS3 solvent, once the total cost of MEA solvent and HS3 solvent was \$63.1/ton CO_2 and \$60.2/ton CO_2, respectively.

6.1 Future work

While the REALISE project has made significant progress in understanding the current status and economic aspects of implementing CCUS in the refineries of China, additional investigations and research are highly recommended to further improve the efficiency and cost-effectiveness of this technology. Some of the key areas for future work include:

- Explore advanced solvents for CO_2 to improve carbon capture performance and waste heat utilization efficiency.
- Develop advanced CO_2 capture processes suitable for complex refinery scenarios with multiple-stack emissions and diverse waste heat distributions.
- Optimize the utilization of waste heat from refineries through innovative heat integration approaches, like employing heat pumps, organic Rankine cycles, etc.
- Conduct comprehensive process modelling, TEA study, and life cycle analysis across the entire CCUS value chain to gain profound insights and knowledge into the successful deployment of CCUS in refineries.

References

1. Energy Information Administration, 2022. Country Analysis Executive Summary: China. ttps://www.eia.gov/international/content/analysis/countries_long/China/china.pdf

2. International Energy Forum, 2019. China Refining Industry Outlook and Oil Demand Peak. https://www.ief.org/_resources/files/events/ief-sinopec-lecture---25-march-2019/china-refining-industry-outlook-and-oil-demand-peak.pdf

3. Ministry of Science and Technology of China. China Carbon Dioxide Capture, Utilization and Storage (CCUS) Annual Report, 2023. https://www.globalccsinstitute.com/wp-content/uploads/2023/03/CCS-Progress-in-China-CN.pdf; English version in https://www.globalccsinstitute.com/wp-content/uploads/2023/03/CCUS-Progress-in-China.pdf

4. Hill, L.B., Li, X. and Wei, N., 2020. CO2-EOR in China: A comparative review. International Journal of Greenhouse Gas Control, 103, p.103173.

5. Yang, W., Peng, B., Liu, Q., Wang, S., Dong, Y. and Lai, Y., 2017. Evaluation of CO2 enhanced oil recovery and CO2 storage potential in oil reservoirs of Bohai Bay Basin, China. International Journal of Greenhouse Gas Control, 65, pp.86-98.

6. Documentary of Liaohe Oilfield building CCUS industry chain. http://center.cnpc.com.cn/sysb/system/2022/03/31/030064015.shtml

7. Matteo Gilardi, Davide Bonalumi. REALISE D3.2. Integration of CO2 capture plant in refineries, 2023.

8.Van Wagener, D.H. and G.T. Rochelle, Stripper configurations for CO2 capture by aqueous monoethanolamine and piperazine. Energy Procedia, 2011. 4: p. 1323-1330.

9. Seider, W. D., Lewin, D. R., Seader, J. D., Widagdo, S., & Gani, R. (2016). Chapter V, Heuristics for Process Synthesis. In Product and Process Design Principles: Synthesis, Analysis and Evaluation (Fourth Edition).

10. International Energy Agency Greenhouse Gas Programme, 2013. Toward a Commons Method of Cost Estimation for CO2 Capture and Storage at Fossil Fuel Power Plants. https://documents.ieaghg.org/index.php/s/qTSgQzfdjIMbm0M

11. DOE/NETL. Carbon Dioxide Capture from Existing Coal-Fired Power Plants, 2007. https://www.globalccsinstitute.com/archive/hub/publications/159713/carbon-dioxide-capture-existing-coal-fired-power-plants.pdf

12. Global CCS Institute. Technology Readiness and Costs for CCS, 2021 https://www.globalccsinstitute.com/wp-content/uploads/2021/03/Technology-Readiness-and-Costs-for-CCS-2021-1.pdf

13. Simon Roussanaly, Rahul Anantharaman, Kristin Jordal, Chiara Giraldi, Annalisa Clapis, 2017. ReCAP Project: Understanding the Cost of Retrofitting CO2 capture in an Integrated Oil Refinery. https://www.sintef.no/globalassets/project/recap/d5_recap-deliverable-d5-report.pdf

14. Kvamsdal, H. M., J. Hetland, G. Haugen, H. F. Svendsen, F. Major, V. Kårstad and G. Tjellander (2010). "Maintaining a neutral water balance in a 450MWe NGCC-CCS

power system with post-combustion carbon dioxide capture aimed at offshore operation." International Journal of Greenhouse Gas Control 4(4): 613-622.

15. van der Spek, M., S. Roussanaly and E. S. Rubin (2019). "Best practices and recent advances in CCS cost engineering and economic analysis." International Journal of Greenhouse Gas Control 83: 91-104