Using Carbon Capture and Storage Technology to Reduce CO2 Emissions from Power Systems

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I declare that this document is an original work of my own authorship and that it fulfils all the requirements of the Code of Conduct and Good Practices of the *Universidade de Lisboa*.

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Abstract

This thesis explores the pivotal role of Carbon Capture, and Storage (CCS) technology in mitigating CO_2 emissions from Poland's power systems, crucial for maintaining energy security. With a predominant reliance on fossil fuels, particularly coal, accounting for 77% of electricity generation and 53.4% of carbon emissions, the study evaluates the potential of CCS adoption. Acknowledging natural gas as a transitional fuel, the focus is on evaluating the decarbonization potential of gas-fired power plants. The emphasis lies also in utilizing offshore aquifers in the Baltic Sea as a storage sink for CO_2 emissions, drawing comparisons with the Sleipner benchmark.

The thesis emphasizes the need for sustainable solutions that balance environmental concerns with energy security. By integrating surface capture processes and underground storage, the research aims to develop a comprehensive approach to efficiently capture and store CO_2 emissions while prioritizing energy efficiency. Computer simulations, employing IPSEpro, calculate heat and mass balances, allowing the evaluation of amine-based CO_2 capture systems and the energy efficiency of power plants. The Integrated Environmental Control Model (IECM) facilitates the analysis of modelled emissions from the Natural Gas Combined Cycle (NGCC) power plant, providing insights into CO_2 dynamics for informed decision-making in implementing CCS projects. This research contributes to advancing CCS technologies, supporting the transition to sustainable, low-carbon energy systems in Poland.

Resumo

Esta tese explora o papel fundamental que as tecnologias de captação, e armazenamento de Carbono (CAC) desempenham na mitigação das emissões de CO_2 provenientes dos sistemas energéticos na polónia, sendo estes cruciais para a manutenção da segurança energética. Estando estes predominantemente dependentes de combustíveis fósseis, particularmente o carvão, sendo este responsável por 77% da produção elétrica e 53.4% das emissões de carbono. Este estudo revela o potencial da adoção das tecnologias de CAC. Reconhecendo gás natural como um combustível de transição, o foco é posto na avaliação do potencial de descarbonização de centrais elétricas a gás e na utilização de aquíferos “offshore” no Mar Báltico como armazenamento de CO_2, obtendo comparações com a referência de sleipner

Esta tese enfatiza a necessidade de soluções sustentáveis que contribuam para um equilíbrio entre preocupações ambientais e segurança energética. Integrando processos de captação superficial e subterrânea, este estudo aborda compreensivamente a captura e armazenamento eficiente de emissões de CO_2, priorizando a eficiência energética.

Simulações computacionais, empregando IPSEpro, calculam equilíbrios de calor e massa, permitindo a avaliação de sistemas de captura de CO_2 à base de aminas e a eficiência energética de centrais elétricas. O Modelo de Controlo Ambiental Integrado (MCAI) facilita a análise das emissões modeladas da central de produção combinada de gás natural (CCGN), oferencendo informações sobre as dinâmicas de CO_2 para tomar decisões informadas para implementação de projetos de CAC. Este estudo contribui para o avanço das tecnologias de CAC, suportando uma transição sustentável na Polónia.

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Nomenclature

Green House Gas Emissions	GHGE
Carbon Capture and Storage	CCS
Carbon Capture Utilization and Storage	CCUS
Intergovernmental Panel on Climate Change	IPCC
Sixth Assessment Report	AR6
International Energy Agency	IEA
Remaining Carbon Budget	RCB
Enhanced Oil Recovery	EOR
Integrated Environmental Control Model	IECM
Gross Domestic Product	GDP
Global Energy and Climate	GEC
Net Zero Emissions by 2050 Scenario	NZE
Announced Pledges Scenario	APS
Stated Policies Scenario	STEPS
EU Emissions Trading System	EU ETS
Emission Unit Allowances	EUAs
Direct Air Capture	DAC
Renewable Energy Sources	RES
Górnośląsko-Zagłębiowska Metropolia	GZM
Water Gas Shift	WGS
Monoethanolamine	MEA
Methyl	MDEA
Diethanolamine	DEA
Carbon Monoxide	CO
Carbon Dioxide	CO2
Hydrogen	H2
Nitrogen	N2
Nitrogen Oxides	NOx
Nitrogen Dioxide	NO2
Methane	CH4
Sulphur	S
Sulphur Dioxide	SO2
Sulphur Oxides	SOx
Megapascal	MPa
Instytut Chemicznej Przeróbki Węgla	IChPW
Upper Silesian Coal Basin	USCB
Integrated Gasification Combined Cycle	IGCC
Natural Gas Combined Cycle	NGCC
Heat Recovery Steam Generator	HRSG
General Electrics	GE
Megawatts	MW
Kilowatts	kW
Gigatons of CO2	Gt CO2

Chapter 1

1. Introduction

1.1. Motivation

The motivation for this thesis is driven by the need to reduce Poland's carbon dioxide (CO2) emissions, given the country's heavy dependence on fossil fuels. In particular, coal dominates the energy landscape, accounting for 77% of the country's total electricity generation and contributing to 53.4% of carbon emissions in the electricity, heating and industry sectors. This significant dependence on coal underscores the critical need for transformative measures to curb emissions and transition to a more sustainable energy model. Focusing on Carbon Capture, and Storage (CCS) technology, the thesis aims to deploy CCS as a transition solution by recognizing that energy and industrial sectors forms the backbone of the Polish economy, the thesis aligns the deployment of CCS with the goal of reducing CO2 emissions and providing insights into mitigating the environmental impact of fossil fuels, offering a practical approach to a sustainable, low-carbon energy future in Poland.

1.2. Objectives

The main objective of this thesis is to evaluate the use of CCS in a NGCC power plant in Poland as a solution to reduce CO2 emissions taking into account all energy requirements and penalties associated with the integration of the capture unit. In addition, the aim of the thesis is also to discuss:

1. **Assessing CCS Technology in Poland:** Evaluate the effectiveness of CCS technology in reducing CO2 emissions from NGCC power systems in Poland.
2. **Focus on Gas-fired Power Plant Decarbonization**: Investigate the potential of decarbonizing gas-fired power plants as a transitioning fuel in Poland's energy mix.
3. **Closure of the CO2 Emission Loop:** Establish a research framework that prioritizes energy efficiency and aims to close the loop on CO2 emissions through effective capture and storage.
4. **Utilization of Sleipner Benchmark**: Explore the feasibility of using the Sleipner benchmark, as a storage site for CO2 emissions, drawing inspiration from a similar project in the Baltic area.
5. **Contribution to Advancement of CCUS Technologies:** Contribute to the development of CCUS technologies and their practical application, with a specific focus on their role in achieving sustainable and low-carbon energy systems in Poland.
6. **Modelling the CO2 capture Using IPSEpro:** Evaluate the amine-based CO2 capture system and the energy efficiency of the power plant.
7. **Integrated Environmental Control Model (IECM) Analysis**: Enhance understanding of CO2 dynamics and provide insights for informed decision-making in the implementation of CCS projects in Poland.

1.3. Outline

The thesis is structured into four chapters:

Chapter 1. Introduction
Provides the scope and motivation for the thesis, defining the objectives and giving an insightful overview of the subsequent chapters.

Chapter 2. CO2 and Consumption of Fossil Fuels
It takes an in-depth look at the interaction between CO2 emissions and fossil fuel consumption. It covers emissions from energy production, analyses the EU's CO2 strategy and highlights the role of carbon capture and storage CCS. The chapter also analyses Poland's energy mix and explores the application of CCS in the country's energy systems and its potential contributions to tackling CO2 emissions in the national energy landscape.

Chapter 3. CCS Explained in the Polish Context

Chapter 2 explains Carbon Capture and Storage (CCS) within the Polish context. It covers the technology of CO2 sequestration, including Capture, Transportation/Infrastructure, and Injection/Storage. The chapter also discusses the current state of CCS technology and explores the cost and performance baseline for fossil energy plants.

Chapter 4. CO2 Capture and Storage

Focus on CO2 Capture and Storage through detailed case scenarios. For CO2 Capture, the chapter employs IPSEpro software to study a NGCC Power Plant, delving into modelling aspects and presenting results on power, efficiency, and CO2 emissions. Shifting to CO2 Storage, a case scenario is explored using the Integrated Environmental Control Model (IECM), examining both modelling and results, with a specific emphasis on the geological setting. The chapter concludes by summarizing key insights gleaned from both case scenarios, providing a comprehensive overview of CO2 Capture and Storage in the context Poland.

Chapter 2

2. CO2 and Consumption of Fossil Fuels

The industrial revolution marked a significant milestone in human history. The societal growth and development of large-scale economies that most countries have experienced can be attributed to the benefits derived from this transformative period. However, achieving more convenient, efficient, and productive industrial processes necessitates a reliable source of energy. In this regard, the availability of fossil fuels has played a crucial role, in creating an ideal environment for industrialization to flourish.

The widespread utilization of fossil fuels since the latter half of the 18th century not only fueled the rapid ascent of the first Industrial Revolution but also led to a significant surge in greenhouse gas emissions (GHGs)[1]. This is primarily attributed to the combustion of fossil fuels, which releases substantial quantities of carbon dioxide into the atmosphere, making it the primary driver behind the escalating levels of GHGs. Figure 2.1 shows the Keeling Curve, which depicts the accumulation of carbon dioxide in the Earth's atmosphere based on continuous measurements taken at the Mauna Loa Observatory on the island of Hawaii from 1958 to the present day[2].

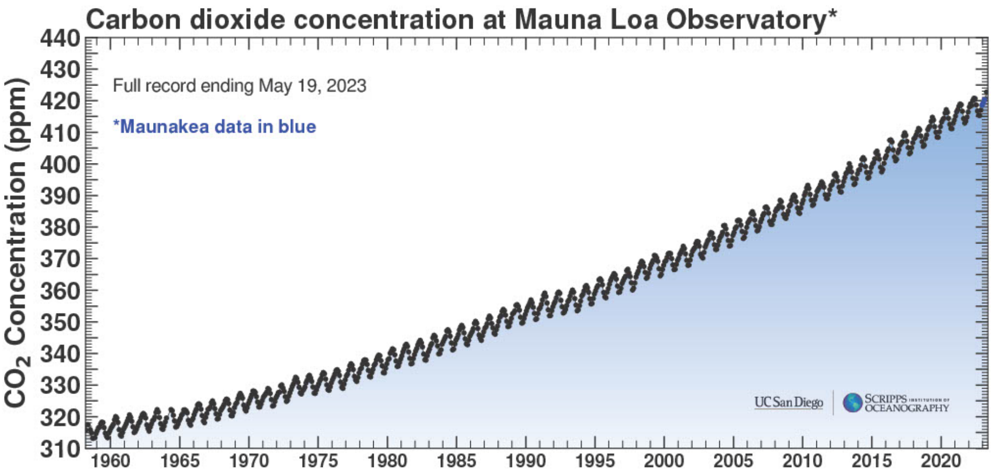

Figure 2. 1. Measured CO2 Concentration at Mauna Loa Observatory, Hawaii.

Credit: Scripps Institution of Oceanography[2]

The Mauna Loa Observatory, located on the island of Hawaii, has been monitoring atmospheric CO2 concentrations since 1958. These measurements, known as the Keeling Curve, have consistently shown a year-on-year increase in CO2 levels. In 1958, the atmospheric CO2 concentration stood at around 310 parts per million (ppm). However, as of early 2023, it has surpassed the **420-ppm** mark, with a constant upward trend of approximately 2+ ppm CO2 per year. Anthropogenic activities are directly responsible for the significant release of carbon dioxide into the atmosphere, thereby contributing to the greenhouse effect and subsequent global warming[3].

According to the Sixth Assessment Report (AR6) of the Intergovernmental Panel on Climate Change (IPCC), the burning of fossil fuels accounts for more than 80% of total anthropogenic CO2 emissions[4]. In order to mitigate the serious consequences of warming above 1.5°C, effective measures must be taken urgently. Unfortunately, despite overwhelming evidence that emissions of fossil fuels play a vital role in global warming, their use continues and shows no signs of diminishing. Energy combustion and industrial processes release approximately **36.5 Gt CO2**[5] per year. The graph below shows global CO2 emissions for different fuels over time. The findings the Global Carbon Project's 2022 Global Carbon Budget Report reveal that coal emits more than any other fossil fuel, highlighted in Figure 2.2 with a shaded grey area, accounting for around 40% of global fossil fuel CO2 emissions in 2022. Oil (red) is the second largest contributor at 32% of fossil CO2, while gas (blue) and cement production round out the pack at 21% and 4%, respectively[6].

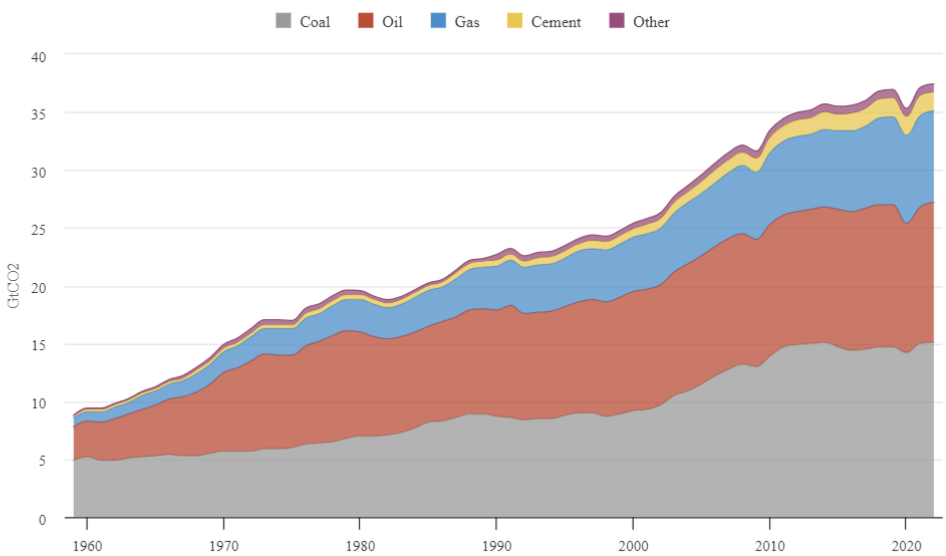

Figure 2. 2. Annual CO2 emissions by fuels from 1959 to 2022.

Credit: Carbon Brief [6].

The "remaining carbon budget" (RCB) plays a crucial role in the pathway to limit global warming below the thresholds of 1.5 or 2 degrees Celsius[7]. This importance is underscored by projections that if annual CO2 emissions persist at current levels until 2030, nearly half of the remaining carbon budget for 1.5°C would be consumed, while more than a third of the remaining budget for 2°C would be depleted[4]. Essentially, the RCB represents the amount of CO2 that can still be emitted in the future while keeping cumulative net CO2 emissions within a defined carbon budget. According to research, for every 1000 Gt CO2 released by human activities, the global mean temperature is projected to increase by approximately 0.27°C–0.63°C, with a best estimate of 0.45°C. This relationship underscores the existence of a finite carbon budget that must not be surpassed to achieve specific warming targets. The best estimates for the RCB as of the beginning of 2020 indicate a limit of **500 GtCO2** to limit warming to 1.5°C with a 50% likelihood, and **1150 GtCO2** for a 2°C target with a 67% likelihood, as depicted in Figure 2.3.

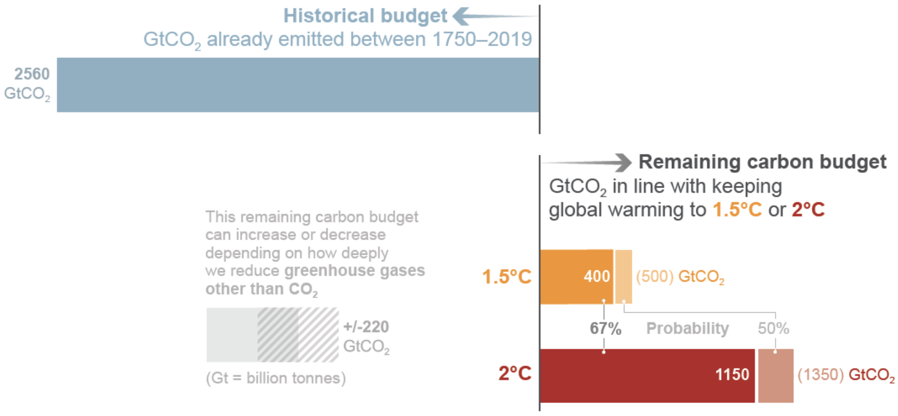

Figure 2. 3. Various types of carbon budgets.

Credit: Global Carbon and Other Biogeochemical Cycles and Feedbacks [7]

The historical budget reflects the cumulative amount of CO2 that has already contributed to global warming, whereas the remaining carbon budget represents the allowable amount of CO2 that can still be emitted to limit warming below specific temperature thresholds. As mentioned earlier, the annual global emissions of CO2 currently stand at approximately **36.5 billion tonnes** in 2022, resulting in an average daily emission of **100 million tonnes** (0.1 billion tonnes), therefore every tonne counts. Hence, each individual tonne emitted counts, as every reduction contributes to mitigating climate change.

2.1. Emissions from Energy Production

Historically, the energy sector has been the primary source of anthropogenic greenhouse gas emissions worldwide[8]. Based on the data presented in Figure 2.4 (2019), this sector accounted for a substantial 76% of the total emissions. The energy sector encompasses a wide range of activities, including transportation, electricity and heat generation, buildings, manufacturing and construction, fugitive emissions, and other fuel combustion. It is important to note that other sectors also play a significant role in contributing to greenhouse gas emissions. For instance, the agriculture sector, which includes livestock rearing and crop cultivation, contributes approximately 12% of emissions. Additionally, industrial processes involving chemicals, cement production, and other activities contribute approximately 6.1% of emissions.

Within the energy sector, the largest proportion of greenhouse gas emissions can be attributed to heat and electricity generation, accounting for a significant 42% of the total. Transportation closely follows, contributing 22% of the overall emissions. Additionally, manufacturing and construction activities account for 17% of the total emissions, as indicated in Figure 2.5 from the same year.

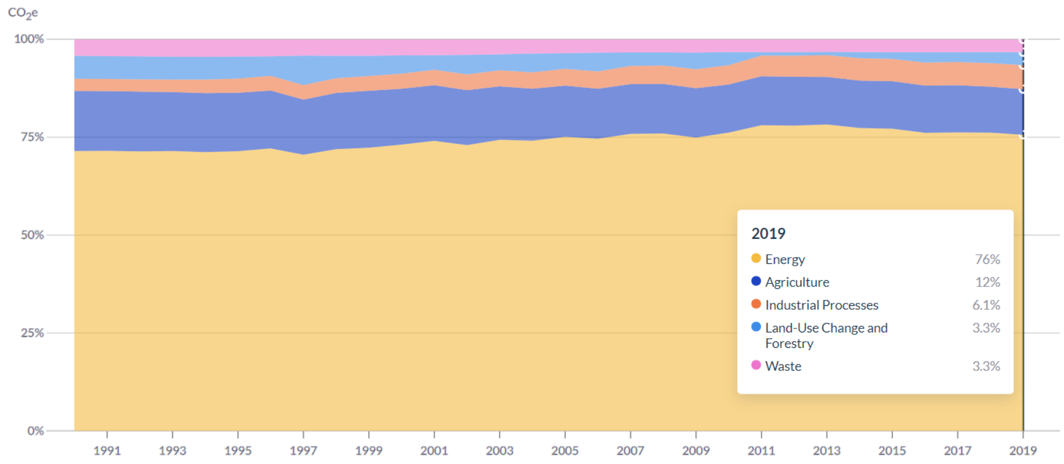

Figure 2. 4. Historical Greenhouse Gas Emissions, 1990 - 2019.

Credit: Adapted from Climate Watch[9].

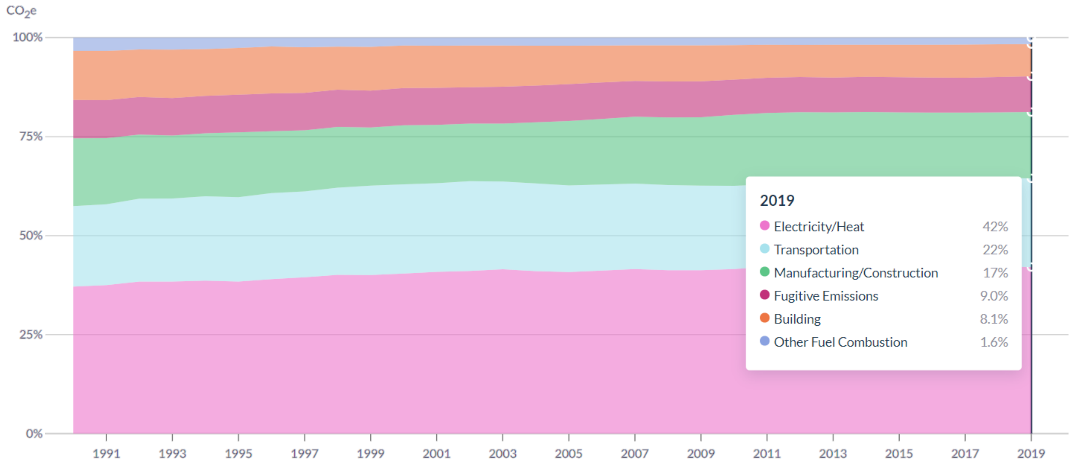

Figure 2. 5. Historical Greenhouse Gas Emissions within the Energy Sector, 2019.

Credit: Adapted from Climate Watch[9].

Energy will remain in high demand due to the need for industrialization and economic development. Societies will continue to rely on heating and cooling, and shifting away from fossil fuels, while desirable, may not be financially or technically viable at present. However, in order to transition to cleaner energy sources and curb the escalating greenhouse gas (GHG) emissions, it is crucial to invest in the development of new technologies and improve energy efficiency systems. Renewable energy alone cannot serve as the sole solution, as it requires complementary measures to ensure reliability, sustainability, and dispatchability. In order to effectively address the need for decarbonization and achieve a substantial reduction in GHG emissions, it is imperative to conduct a comprehensive assessment of the methods, technologies, and sources utilized for energy production. Additionally, it is essential to focus attention on the major contributors to the overall CO2 emissions. By thoroughly evaluating these aspects, we can identify key areas for improvement and implement effective strategies to mitigate emissions and drive the transition to a low-carbon future.

The urgency of transitioning to a low-carbon energy system stems from the alarming rate at which we are depleting our carbon budget. The RCB required for stabilizing global temperatures at 1.5°C by 2020 was estimated at 300 GtCO2 [10]. Europe and North America already emit a large share of GHG, with Europe accounting for 27% and North America 22%, as shown in Figure 2.6. From the current rate of carbon emissions of about 37 GtCO2, it is clear that achieving the 1.5°C target is a major challenge. In a more realistic scenario, the focus shifts to a 2°C stabilisation by 2050, incorporating a remaining carbon budget (RCB) of 900 billion tonnes of CO2 [10]. This scenario underlines the imperative for decisive action, as it suggests that reaching the 1.5°C target may be unavoidable unless decisive action is taken promptly. The specified RCB serves as a tangible benchmark, underlining the critical need for effective and immediate strategies to mitigate the impacts of climate change.

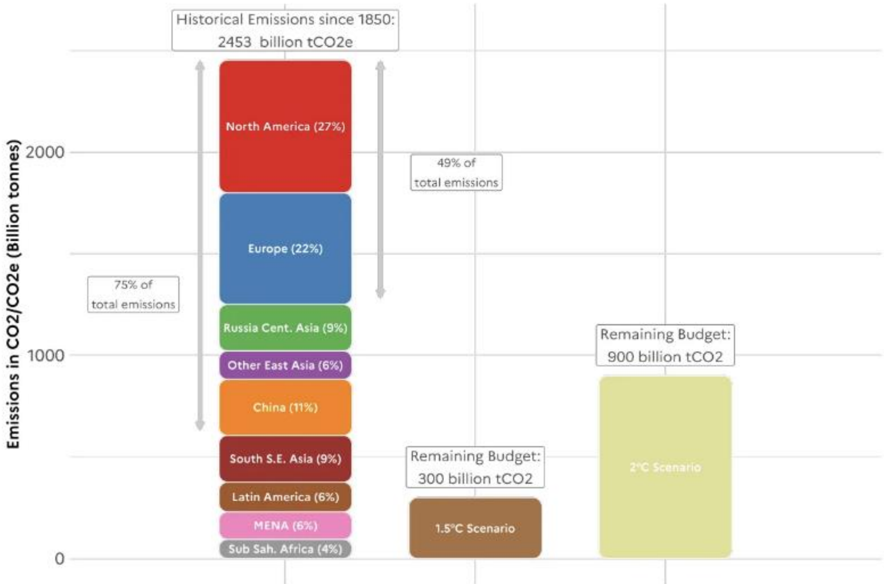

Figure 2. 6. Accumulated historical CO2 emissions vs remaining carbon budgets 2020.

Credit: The triple inequality of the "global" climate problem [10].

Figure 2.7, sourced from the Global GHG Emissions 2019, provides valuable insights into the leading contributors to global CO2 emissions. China emerges as the largest emitter with 26.4% of the world's greenhouse gas emissions, followed by the United States at 12.5%, India at 7.06%, the European Union at 7.03% (EU27) and Japan 2.4% [11]. Notably, these countries also possess the highest Gross Domestic Product (GDP)[12] and collectively account for 60% of global fossil fuel consumption and 61% of global fossil CO2 emissions [13]. While Figure 2.7 provides a comprehensive overview of GHG emissions for the entire European Union (EU27), it is crucial to analyse the individual performance of EU countries, especially those that are significant emitters within the region.

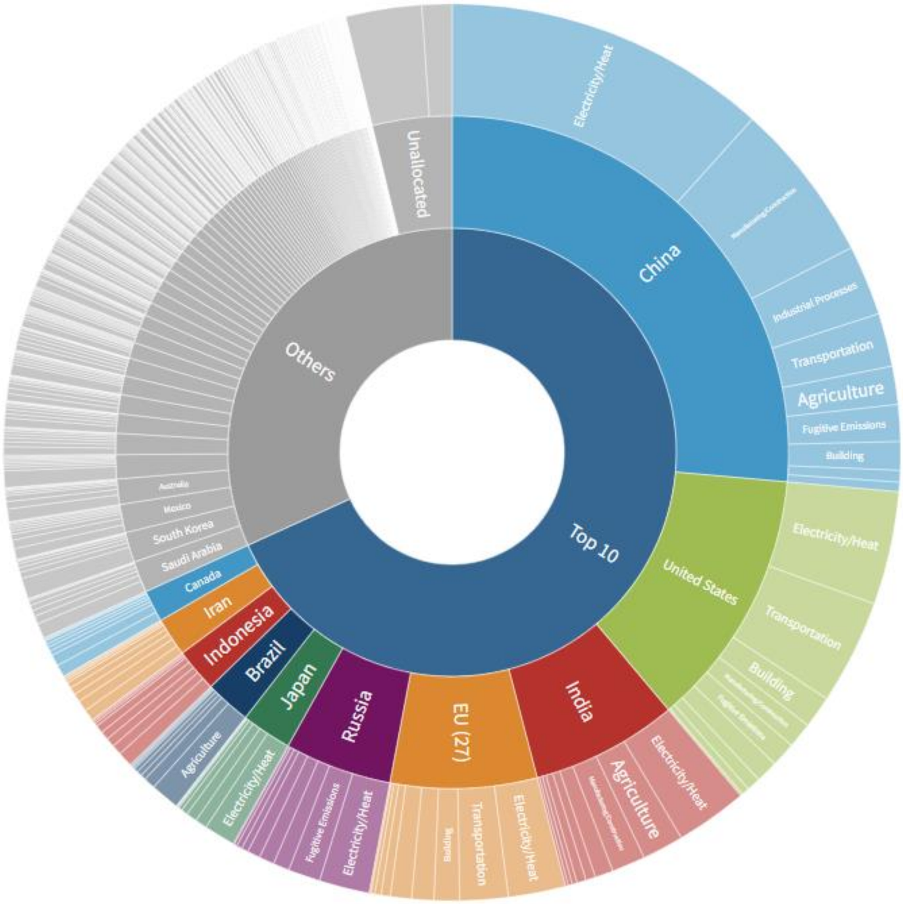

Figure 2. 7. The Top 10 GHG Emitters Contribute Over Two-Thirds of Global Emissions.

Credit: Climate Watch [9].

Figure 2.8 provides valuable insights into the emissions of key European countries, such as Germany, Italy, Poland, France, and Spain. Additionally, Portugal and Colombia are included as examples of countries with comparatively low GHG emissions. This representation provides a nuanced perspective on the emission profiles of both major European nations and those with lower GHG contributions. Germany, Italy, Poland, France, and Spain exhibit the highest overall GHG emissions ranging from approximately **250 to 647 million tonnes**. Collectively, the EU countries contribute around **2,825.5 million tonnes of CO2** equivalent to the total emissions. As mentioned previously, the elevated emissions levels of these countries can be attributed to their heavy reliance on fossil fuels. Notably within the EU, Poland and Germany are prominent examples, with a significant dependency on fossil fuels as their primary energy source. Moreover, these countries possess some of Europe's largest coal-fired power plants.

Contrastingly, Portugal, despite a heavy dependence on imported fossil fuels constituting 76% of its primary energy supply in 2019, has demonstrated significant advancements in achieving a high level of electrification. Notably, the country has made substantial strides in integrating renewable energy sources into its energy mix. In fact, renewables covered 30.6% of Portugal's gross final energy demand in 2019, with a significant contribution from hydropower and wind generation. Moreover, renewables accounted for 54% of electricity generation[14]. On the other hand, Colombia is a major coal producer but uses very little coal domestically. Instead, the country primarily exports its coal production. Similar to Portugal, Colombia relies heavily on hydropower, with renewables accounting for 73% of its total generation[15].The majority of this renewable energy comes from hydropower dams. In countries where alternative energy sources are not as readily available, like Poland, the challenge lies in meeting their energy demand while effectively reducing their net emissions. This is crucial to contribute to the global efforts aimed at achieving net-zero greenhouse gas (GHG) emissions by 2050 and mitigating the severe impacts of climate change. To this end, there is a technology solution that is well recognised by authoritative bodies such as the Intergovernmental Panel on Climate Change (IPCC) and the International Energy Agency (IEA) as having the potential to significantly reduce, if not completely eliminate, CO2 emissions from numerous sources. This is Carbon Capture and Storage and Utilisation (CCUS).

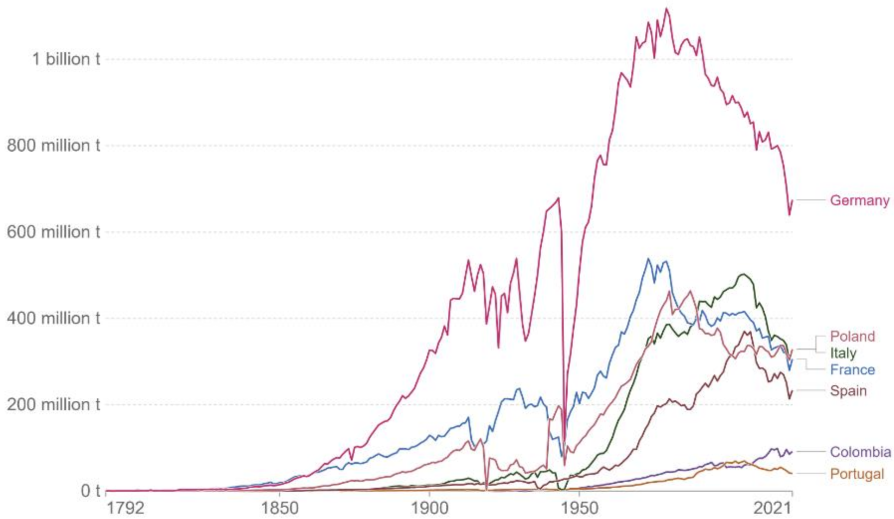

Figure 2. 8. Top CO2 emitters in EU27 Including Portugal and Colombia data, 1792-2021.
Credit: Adapted from Our World in Data [16].

2.2. The strategy for EU

The International Energy Agency (IEA) has recognized the urgent need to address climate change and has developed three distinct scenarios using the Global Energy and Climate (GEC) Model. These scenarios are shown in Figure 2.9, namely the Net Zero Emissions by 2050 Scenario (**NZE**), the Announced Pledges Scenario (**APS**), and the Stated Policies Scenario (**STEPS**)[17]. In all three scenarios, the IEA emphasizes the importance of CCUS in the energy sector, the IEA underscores the need for increased investments, supportive policies, and international collaboration to accelerate the development and deployment of CCUS technologies. Successful implementation of CCUS, as outlined in these scenarios can provide a viable pathway for the energy sector to significantly reduce its emissions, mitigate climate change, and facilitate the transition to a sustainable and decarbonized global energy system.

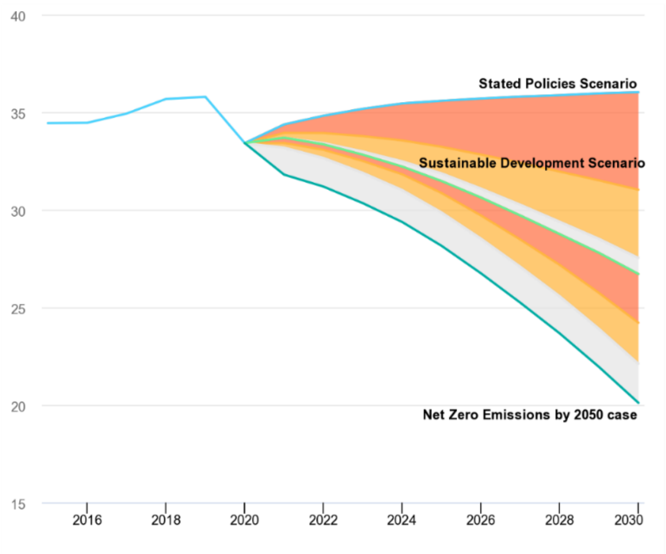

Figure 2. 9. Energy and industrial process CO_2-emissions and reduction levels in 2020 scenarios. Credit: World Energy Outlook 2020[17].

Moreover, the European Green Deal, which outlines the EU's long-term growth plan to achieve climate neutrality by 2050, includes the European climate law that mandates EU countries to reduce greenhouse gas emissions by at least 55% by 2030. The EU's objective is to become climate neutral by 2050. A crucial component of the EU's efforts toward climate neutrality is the **Fit for 55 Package**[18]. This comprehensive package aims to translate the aspirations of the Green Deal into enforceable legislation and covers various areas, including energy, transport, emissions trading and reductions, as well as land use and forestry.

To achieve these goals, the EU will utilize the EU emissions trading system (**EU ETS**), a "cap-and-trade" mechanism. The EU ETS sets a cap on the total number of Emission Unit Allowances (EUAs) available each year, with the cap progressively decreasing over time[19]. Entities covered by the ETS, which include electricity and heat generation, energy-intensive industries (such as oil refineries, steel production, cement, glass, and paper manufacturing), and commercial aviation within the Euro Economic Area, are required to purchase allowances corresponding to their greenhouse gas emissions. This system currently covers approximately 40% of total EU emissions and has proven to be a vital tool for reducing emissions. Since its introduction in 2005, EU emissions in the covered sectors have been reduced by 41% [19].

High-emitting entities can choose to reduce their emissions or purchase additional EUAs or other recognized credits, such as Certified Emission Reductions (CERs) from developing countries. The price of EUAs is determined by supply and demand dynamics in the market. In December 2022, the Council and the European Parliament reached a provisional political agreement on the reform of the ETS. The new legislation was formally adopted by the Council in April 2023. This reform will result in further emissions reductions, with the EU ETS sectors targeting a 61% reduction by 2030 compared to 2005 levels, instead of the previous goal of 43%. The reform will lead to a lower emissions cap and consequently, a higher price of CO2 within the ETS market [20].

Quote from the European Council: "Climate neutrality means emitting less and absorbing more"[21]. This means that in addition to reducing greenhouse gas emissions, climate neutrality means offsetting all remaining emissions. A net-zero emissions balance is then achieved when the amount of greenhouse gases released into the atmosphere is neutralized, one of which can be achieved through carbon sequestration. Achieving climate neutrality by 2050 will be a greater challenge for some member states and regions than for others. For example, some countries are more dependent on fossil fuels or have carbon-intensive industries that employ large numbers of people[22]. Numerous funding programs have been implemented by the EU to support the development of low-carbon technologies. One program is the Innovation Fund, which provides financial support for the implementation of low-carbon technologies, or the Just Transition Fund (JTF), which offer support to regions that face greater challenges in their transition attempts. These initiatives, among others, are easing the transition to member nations that require additional funding to achieve their decarbonization objectives.

Most recently, in March 2023, the European Commission published the Net Zero Industry Act, supporting the EU's commitment to achieve climate neutrality by 2050, including net zero greenhouse gas emissions, which is at the heart of the European Green Deal. Specifically, the Net Zero Industries Act (NZIA) supports eight strategic net zero technologies. These are: i) solar photovoltaic and solar thermal technologies; ii) onshore wind and offshore renewables; iii) batteries and storage; iv) heat pumps and geothermal energy; v) electrolyzers and fuel cells; vi) biogas/biomethane; vii) carbon capture and storage (CCS); viii) grid technologies (including smart and fast charging of electric vehicles). The act will simplify the regulatory framework for manufacturing these technologies, thereby helping to increase the competitiveness of Europe's net-zero technology industry. It will also accelerate the ability to capture and store carbon emissions by setting an EU target of 50 Mt CO2 storage capacity per year by 2030 and calling for EU oil and gas producers to proportionally contribute to establishing the required CO2 storage sites in the EU, aim to provide operationally available CO2 injection capacity by 2030 or earlier, and have applied for a permit for the safe and permanent geological storage of CO2, in accordance with Directive 2009/31/EU[23].

2.3. CCUS Overview

Carbon capture, utilisation and storage (CCUS) is a focused approach as a climate change mitigation strategy. The process begins with the capture of CO2 emissions from major industrial point sources, including operations such as cement and chemical production, coal and biomass plants. Using a variety of capture methods, such as post-combustion and pre-combustion techniques, CCUS effectively removes CO2 before it is released into the atmosphere. The captured CO2 is then purified and compressed, transforming it into a liquid state. What sets the CCUS apart is its versatility; beyond storage, there is a growing emphasis on carbon utilisation. This involves reusing captured CO2 for industrial applications or converting it into valuable products, fostering a circular carbon economy.

After capture and utilisation, the final stage is to transport the CO2 to suitable storage sites. Typically, underground geological formations, such as depleted oil and gas fields, coal beds or saline aquifer formations, serve as safe storage sites. Transportation itself is via pipelines, ships or tankers, and ship transport is emerging as a viable alternative for many regions of the world. Indeed, the entire process of CCUS, as illustrated in Figure 2.10, holds the potential to address global emissions and fostering a more sustainable future.

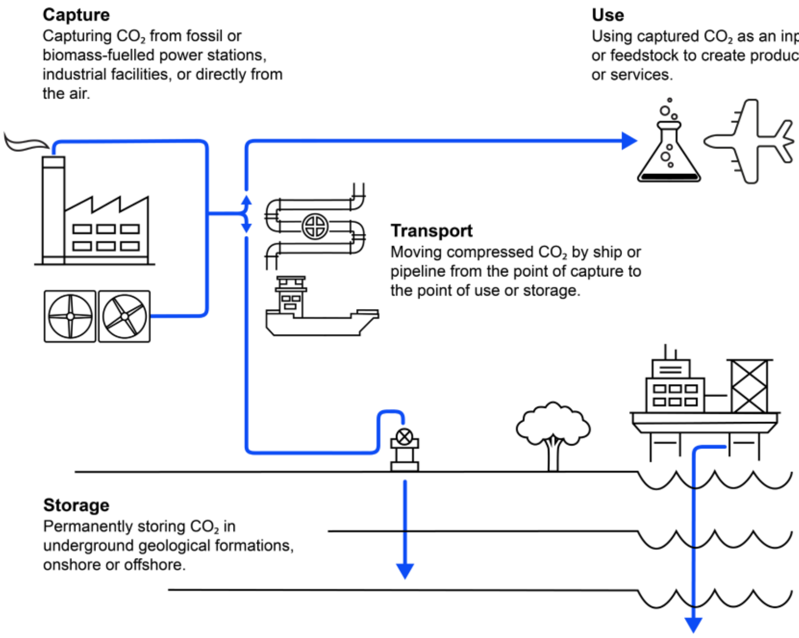

Figure 2. 10. Schematic of CCUS

Credit: About CCUS IEA[24]

2.4. Role of CCUS

CCUS offers the potential to radically reduce CO2 emissions from large sources, including coal and gas-fired power plants. It also presents a significant opportunity to cut emissions from intensive industrial facilities such as those involved in refining, chemicals, cement, iron, and steel [25]. CCS plays an important role as a transition technology and can help these sectors to make a substantial contribution to the mitigation of greenhouse gas emissions and combatting climate change. The mechanism behind CCS involves capturing and removing CO2, an undesirable pollutant before it is released into the environment. The captured CO2 is then safely stored in geological formations, similar to the ones that originally contained the hydrocarbon sources of the carbon.

The importance of CCUS technologies is widely recognized by authoritative bodies such as the Intergovernmental Panel on Climate Change (IPCC) and the International Energy Agency (IEA). The IPCC acknowledges the crucial role of CCUS in most 2°C temperature stabilization pathways, while the IEA highlights its near indispensability in any 1.5°C pathway, as outlined in the Paris Agreement[26,27]. CCUS technologies are considered one of the pillars of global energy transitions, alongside renewables-based electrification, bioenergy, and hydrogen [28].

CCUS plays a central role in several ways. Firstly, it provides a means of removing CO2 from the atmosphere, known as "negative emissions," which can offset emissions from sectors were achieving zero emissions may not be economically or technically feasible. Bioenergy with carbon capture and storage (BECCS) is one example, where CO2 is captured and permanently stored from processes involving biomass burning for energy generation. Direct Air Capture (DAC) is another approach, involving the capture of CO2 directly from ambient air. The captured CO2 can serve various purposes, including its utilization as a feedstock in the production of synthetic fuels. Alternatively, if not utilized, the captured CO2 is compressed to a dense fluid state known as 'supercritical' and transported through pipelines, ships, railways, or trucks until the storage point to be injected either into deep geological formations, depleted oil and gas reservoirs or saline formations, where it can be permanently stored. The effectiveness of CO2 emissions reduction in net terms depends on the extent of CO2 capture from the point source and the subsequent utilization or storage processes [29].

Here are four main ways in which carbon capture, Utilization and storage (CCUS) can significantly contribute to the transition of the global energy system to net-zero emissions [28]: 1. Address emissions from existing fossil fuel power plants and industrial plants, thereby significantly reducing their carbon footprint, 2.Enable low-carbon hydrogen production by capturing CO2 emitted during hydrogen production processes, such as steam methane reforming, 3. Address sectors with hard-to-abate emissions, including heavy industries like steel, cement, and chemicals, thereby facilitating progress towards decarbonization, 4. Removing atmospheric carbon by capturing carbon dioxide directly from ambient air can help offset emissions that are unavoidable or technically difficult to reduce.

These four pillars highlight the diverse and impactful role of CCUS in the global energy transition toward achieving net zero emissions. The significance of these pillars is evident in the IEA Sustainable Development Scenario [28], which envisions global CO2 emissions from the energy sector reaching net-zero by 2070. By 2070, from 36.5 GtCO2 per year, approximately **20%** is projected to be mitigated by

CCUS, which means that 7.3 GtCO2 per year should be captured from the energy sector, where around one-quarter comes from the heavy industries (Figure 2.11). It is worth noting that the CO2 capture capacity under development has grown substantially, reaching 244 Mt CO2 according to the Global Status of CCS 2022 report[30]. However, it is crucial to acknowledge that in order to align with a net-zero by 2050 pathway, the annual carbon capture capacity must increase rapidly.

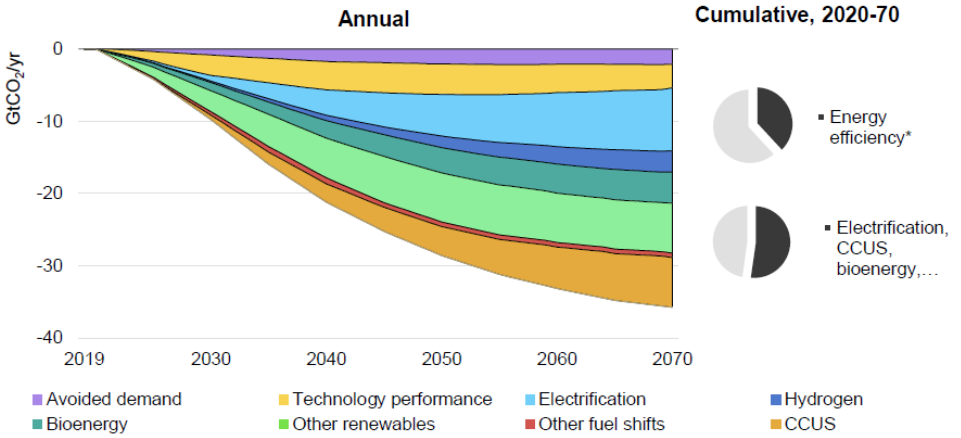

Figure 2. 11. Global energy sector CO2 emissions reductions by measure 2019-2070.

Credit: Energy Technology Perspectives 2020 [17].

Approximately, 6% of the cumulative emissions reductions in both the Sustainable Development Scenario and NZE (Figure 2.11) are from low-carbon hydrogen, with 40% of hydrogen demand met by fossil-based production equipped with CCUS in 2070. Moreover, in the NZE scenario, the total hydrogen production is projected to reach over 500Mt by 2050, and it will contribute to the decarbonization of transport, industry, buildings and power sector. The importance of these values in the whole scheme is given by its increasing share in the total final energy consumption, as seen by Figure 2.12, starting at less than 0.1%, in 2020, this share is expected to reach 2% and 10%, by 2030 and 2050, respectively. This indicates that low-carbon hydrogen will serve as a transition fuel, playing a vital role in achieving neutral emissions while meeting the growing energy demand [28].

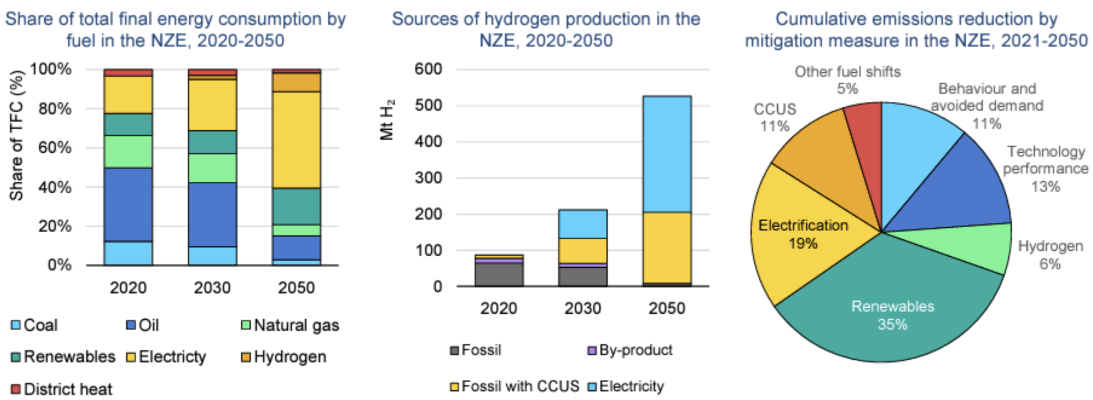

Figure 2. 12. Hydrogen Perspectives NZE Scenario 2020-2050.

Credit: Global Hydrogen Review 2021 [31].

2.5. Energy Mix of Poland

Poland "Polska", officially known as the Republic of Poland, is located in Central Europe and Warsaw is its capital. It is divided into 16 administrative provinces, called voivodeships, as illustrated in Figure 2.13. With an area of 312,696 square kilometres and 38 million inhabitants, the country is the sixth largest and fifth most populous in the European Union [32].

Figure 2. 13. Poland political map.

Credit: Netmaps [33] .

According to the BP Statistical Review of World Energy 2021, Poland's total primary energy consumption in 2021 is 4.4 exajoules, of which about 42% comes from coal, nearly 31% from oil, 19% from natural gas, 6.7% from other renewables and, 0.5% comes from hydro [13]. Coal plays an important role in the Polish energy system and economy. Among IEA member countries, Poland has the highest share of coal in energy production, total energy supply (TES), total final consumption (TFC), and electricity generation, and the second largest share in heat production in 2020. Due to the high share of coal, Poland ranks second among IEA member countries in terms of the carbon intensity of energy supply and fourth for the carbon intensity of GDP [34]. This is why it is crucial to prioritize the reduction of carbon intensity in the energy supply in Poland. This can be achieved through various means, such as increasing the utilization of renewable energy sources, promoting higher electrification of energy demand, improving energy efficiency measures or by implementing negative emissions technologies, such as CCUS.

Figure 2.14 illustrates the distribution of total CO2 emissions in 2021 for Poland. Among the various sectors, Electricity and Heat Production accounted for the highest share at 37.7% (152.3 Mt of CO2), followed by Transportation and Industry at 16.9% and 15.7%, respectively and households amounted to 8.5% of the total emissions, for a total of **403.8 Mt of CO2** recorded that year[35].

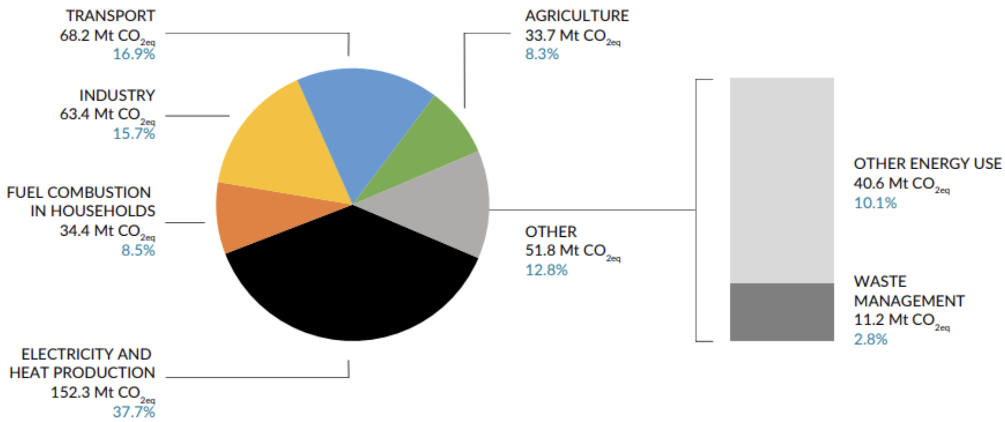

Figure 2. 14. Structure of greenhouse gas emissions in Poland in 2021.

Credit: Energy transition in Poland [35].

Figure 2.15 presents a pie chart illustrating the dominant role of domestic coal-fired generation in Poland's electricity supply. In 2022, the country produced **178.8** TWh of electricity, with fossil fuels accounting for approximately **77%** of the total production share [35]. Among the renewable energy sources (RES), onshore wind energy stands out, contributing 19.4 TWh. This can be attributed to Poland's favourable geographic potential for wind deployment. Furthermore, as part of the Energy Policy of Poland until 2040 (PEP2040-draft), the Polish government has set ambitious goals for the power industry. The policy envisions a gradual reduction in Poland's reliance on coal and simultaneous expansion of offshore wind and photovoltaic installations. The aim is to achieve a minimum share of 32% of renewable energy sources (RES) in the overall power generation [36].

Power generation in Poland has long been heavily reliant on fossil fuels, primarily due to the convenient availability of coal, which has been a driving force behind the country's economic development. However, to align with climate change ambitions, EU members have committed to reducing greenhouse gas emissions by 55% by 2030. Consequently, Poland needs to accelerate its energy transition. Figure 2.15 shows that coal use increased significantly in 2021, and demand returned to levels observed before the onset of the Covid-19 pandemic, Polish energy is lagging behind EU targets. It is crucial to approach this transition prudently to mitigate the potential impact on energy prices, especially given the influence of the EU Emissions Trading Scheme (EU ETS), achieving domestic electricity generation may become a major challenge if fossil fuels are phased out. While Poland has the potential to expand its renewable energy sources, uncertainties persist regarding the pace at which the capacity for power generation can be effectively developed and managed by renewable energy sources (RES) without approaching topics like intermittency, energy storage, and demand management.

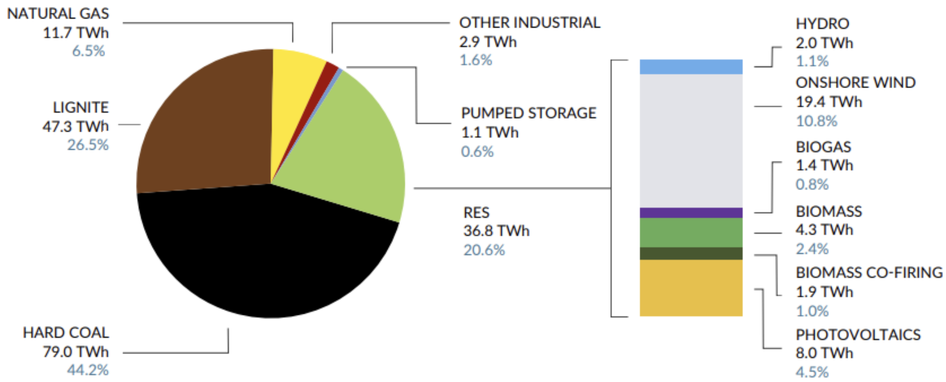

Figure 2. 15. Electricity production in Poland 2022.

Credit: Energy transition in Poland [35].

Developing a comprehensive transition plan for the entire coal value chain is crucial to align with the rapid energy transition required by 2030, promote carbon neutrality, and ensure a just transition. This plan should prioritize the integration of Carbon Capture, Utilization, and Storage (CCUS) technologies, as fossil fuels are expected to remain active in power generation in Poland, it should be considered for applications in coal-based power plants and hard-to-abate industrial facilities. Figure 2.16 illustrates this, showing that despite the ongoing transition away from coal use since 2011, there was a notable increase in coal consumption in 2021 [34]. This increase in demand, which rebounded to pre-pandemic levels, played a vital role in the recovery of the Polish economy during the global crisis. Therefore, it is essential to carefully manage the role of fossil fuels in power generation in Poland while actively pursuing cleaner and more sustainable alternatives.

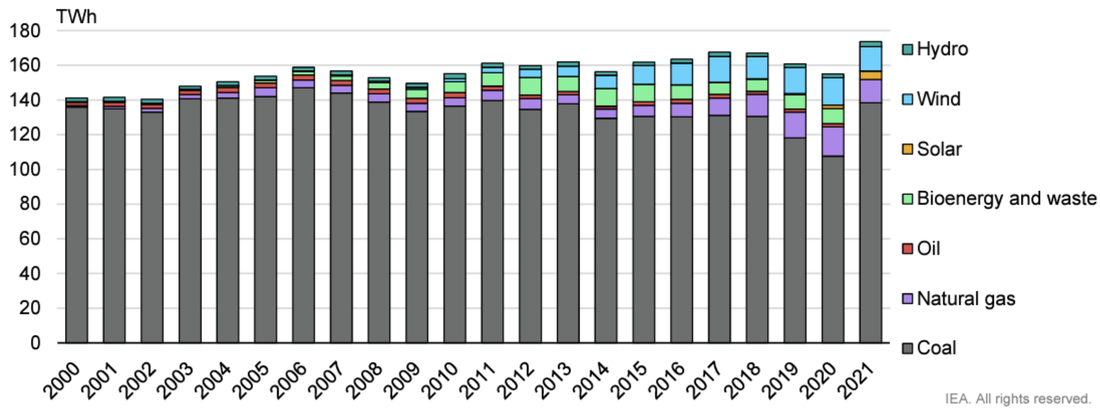

Figure 2. 16. Electricity generation by source in Poland, 2000-2021.

Credit: World Energy Balances 2022 [34].

2.6. CCUS in Power Systems in Poland

The annual anthropogenic CO2 emissions in Poland are estimated to be approximately **400 Mt**, ranking the country third among EU countries in 2021. Out of this total, 210 Mt or 48% of the emissions were covered by the European Union Emissions Trading System (EU ETS), primarily from **commercial power plants and CHP facilities**. It is noteworthy that 96% of all emissions from this sector were subject to the ETS [35], as illustrated in Figure 2.17. Poland is fast approaching a decision point where it must act to secure its future energy supplies as it could become economically vulnerable to climate change regulations amid growing EU regulation of carbon dioxide emissions. Given the need to drastically reduce emissions, renewable energy will eventually need to grow to provide an ever-increasing share of energy. Still, it may not be realistic for Poland to end its dependence on fossil fuels by 2050. CCS technology addresses this challenge by reducing emissions from coal and natural gas power plants by 85-95% [37] and also creating a potential synergy within different industries, as the same technology can be used to tackle increasingly costly CO2 emissions[38].

Investment in CCS could serve as an insurance policy for Poland, allowing the country to freely choose coal, lignite, natural gas or renewables in its energy mix in the short and medium term. However, this strategy also implies investing in prospecting for dedicated CO2 storage sites which involves seismic studies, drilling, well-logging, core analysis etc. Alternatively, repurposing existing infrastructures from oil and gas fields, is a viable option, upon the thorough validation of its integrity, quality, and capacity for CO2 injection. Yet, if existing facilities are not able to handle corrosion, high pressure injections or low temperatures, costly measures such as material replacement, remedial cement jobs, application of coatings, or use of corrosion inhibitors must be taken.

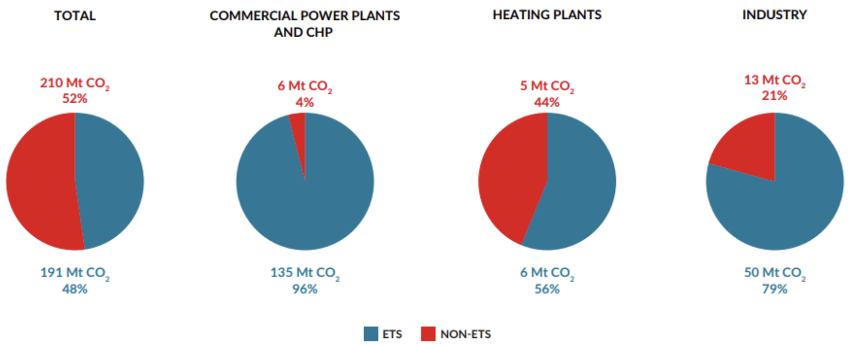

Figure 2. 17. Carbon dioxide emissions covered by the Emissions Trading System (2021).

Credit: Energy transition in Poland [35].

Figure 2.18 highlights significant CO2 emission sources in Poland, most are concentrated in the Southern region, including cement plants, the GZM (Górnośląsko-Zagłębiowska Metropolia) metropolis in Upper Silesia, and the Dąbrowa coal basin. Additionally, the North Central region, which houses assets owned by Anwil, Ciech, Lafarge, Lotos, and Orlen, can also be identified as a CO2 cluster[39].

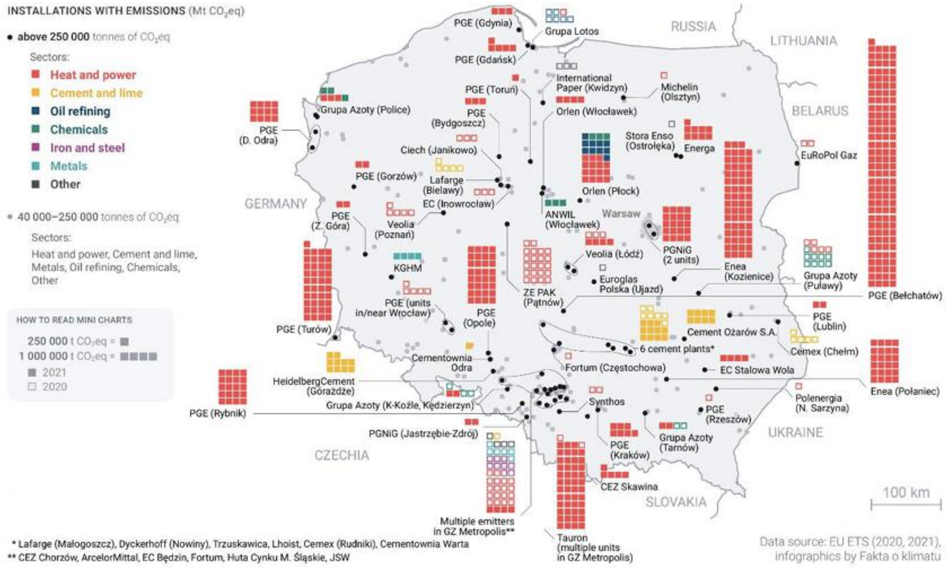

Figure 2. 18. Poland's largest emitters in the EU ETS in 2020 and 2021.

Credit: CCS4CEE 2021 [40].

Even though, it is heard often that CCS is a distraction from the main goal of deploying alternative energies and moving away from a fossil fuel-based society and they are the main to blame for the increase in GHG emissions levels, the scale of polish energy system that relies on them is significant. In Poland there are 72 power plants which may be classified as major point sources of emission (46 power and heat and 26 power plants). The largest are those situated in proximity of open-cast lignite mines, that is at Bełchatów, Konin and Turoszów, and in major industrial centres such as Upper Silesia, as seen in Figure 2.18. Eight plants emit from 5 to 10 Mt per year, and 19 – from 1 to 5 Mt per year, and the remaining 44 plants – less than 1 Mt/y. Bełchatów power plant belong to the Polish Energy Group (PGE), generates more than 20% of the nation's electricity and it is the largest lignite-fired plant in Europe, with a capacity of more than 5.3 GW, but also is the largest single CO2 emitter withing the EU, emitting 30 million tonnes of CO2 per year.

According to the IEA, a more rapid transition to a net-zero emissions economy emphasizes the crucial role of CCUS. They have highlighted that CCUS contributes to nearly 15% of the overall emissions reduction in the Sustainable Development Scenario. Furthermore, revisiting the IPCC statement, which emphasizes the need to capture about 20% of global CO2 emissions to limit global warming below 2 °C, applied in the specific case of Poland, achieving this target means injecting between 21 and 28 million tons of CO2 from commercial power plants alone, and 60 to 80 million tons of CO2 from all sectors, into suitable underground storage sites each year by the end of the century.

When it comes to the readiness of individual countries in implementing CCS technology at a large scale, the Global CCS Institute evaluates their progress through the CCS Readiness Index [39]. According to the latest data from 2021, Poland received a total score of 47 out of 100, which reflects the assessment of various components included in the overall index. In terms of the CCS Requirement Index, which considers the country's share of global fossil fuel production and consumption, Poland scored 51 out of 100, indicating the need for deploying CCS to reduce emissions from fossil fuels, while the legal and regulatory framework received a score of 51 and readiness for CO2 storage, Poland scored 68 out of 100, which reflects sufficient storage potential. However, for the development of the nation's CCS policy, Poland scored 23 out of 100. Such low grade means that Poland needs legislative solutions to implement CCS projects on a large scale[41]. As stated in the roadmap for CCS done by Bellona Foundation for Climate Challenges [38], full implementation of CCS in Poland is considered feasible. However, immediate action is needed to demonstrate the technology, assess potential storage sites and provide a stable Policy support. Taking advantage of the European Union's funding opportunities for CCS demonstration projects, the Belchatow and Kedzierzyn-Kozle projects can greatly benefit. It is crucial to swiftly retrofit the necessary infrastructure onto the power system to shrink the volume of their emissions and test suitable underground sites for injection and monitoring wells, which has been estimated at between 10.1 Gt and 15.5 Gt, the major part of which is located in onshore saline aquifers[39,42].

Additionally, it is essential to develop comprehensive numerical models for two complementary levels. Firstly, at the surface facility, the integration of the power plant and the CO2 capture unit should be carefully designed to achieve the most optimal arrangement. This involves simulating various configurations to determine the most efficient and effective setup. Secondly, it is crucial to simulate CO2 injection and storage in the available underground sinks within Poland. These simulations will help define the necessary number of wells and appropriate injection volumes, ensuring the safe and efficient sequestration of CO2. Surface and underground integrations will greatly enhance and complement the research project on CCUS conducted in this thesis. The primary goal of this research is to establish a comprehensive approach that closes the loop on CO2 emissions, ensuring efficient and effective capture and storage while prioritizing energy efficiency. By integrating these efforts, the thesis aims to contribute to the advancement of CCUS technologies and their application in achieving sustainable and low-carbon energy systems in Poland.

Chapter 3

3. CCS Explained in the Polish Context

Over the past decades, carbon capture, Utilization and storage (CCS) technologies have been utilized to reduce the naturally occurring CO2 content in natural gas, a process known as sweetening. This ensures compliance with market and pipe specifications for the production of liquefied natural gas (LNG). As the focus shifted towards achieving climate neutrality targets, CCS technology evolved to capture CO2 emissions from significant point sources such as industrial processes (e.g., cement production, chemical manufacturing, coal-fired power plants, and biomass facilities). Moreover, CCS plays a crucial role in hydrogen production as an energy carrier, addressing emissions associated with natural gas while offering a cost-effective pathway to meet the growing demand for low-carbon hydrogen in various applications.

This chapter aims to establish a comprehensive framework for understanding CCS by integrating various technologies and disciplines. It will provide an overview of the global status of CCS technology, highlighting its current developments and achievements. Additionally, the chapter will examine the concept of viable routes for CCS deployment while addressing the challenges that need to be overcome. By the end of this chapter, there will have a solid understanding of the fundamental principle of CCS, its worldwide implementation, and the key considerations for successful deployment. The utilization aspect of CCUS will not be addressed further in this thesis. The focus will be limited to the Capture and Storage stages of the process, henceforth referred to as CCS.

3.1. CO2 Sequestration Technology – How it works?

Carbon capture and storage (CCS) is the process of capturing and storing carbon dioxide (CO2) produced in power generation and industrial processes to prevent its release into the atmosphere. CCS technology offers great potential for reducing CO2 emissions in energy systems. Plants equipped with CCS can capture most of the CO2 they produce, with some currently capturing 80% or even 95% [43]. Using CCS in a power plant or industrial plant typically involves three main steps:

3.1.1 Capture

Currently, three main processes are employed for capturing CO_2 and separating it from flue gases generated during the combustion of fossil fuels. These processes are known as post-combustion, pre-combustion, and oxyfuel combustion [44]. Each of these CO_2 capture methods possesses distinct advantages and challenges, and their suitability depends on factors such as the fuel type, facility scale, and desired CO_2 purity. Continuous advancements in these technologies are continuously being made to enhance their efficiency, reduce costs, and improve overall performance, to facilitate widespread adoption of CCS and mitigating greenhouse gas emissions. Next, each process will be described to provide a comprehensive understanding of their principles and applications.

1. **Pre-Combustion:** The fuel undergoes gasification forming syngas ($CO + H_2$). Steam is introduced to facilitate the Water Gas Shift (WGS) reaction, converting CO to CO_2 while generating additional H_2. After the WGS reaction, the CO_2 needs to be separated from the syngas. Various techniques can be employed for CO_2 capture. One common method is physical absorption, where a solvent is used to selectively absorb CO_2 from the syngas. Subsequently, energy is required to separate the CO_2 from the solvent for re-use. Another approach is chemical absorption, involving the use of amine-based solutions to chemically capture CO_2.
2. **Post-Combustion:** The process involves a suitable solvent used to absorb CO_2 from the flue gas. The solvent, often an amine-based solution, comes into contact with the flue gas in an absorber column. The CO_2 molecules react with the solvent, forming a chemical bond and getting captured (chemical absorption). Once the CO_2 is absorbed by the solvent, it needs to be separated to form a high-purity CO_2 stream. To achieve this, the solvent undergoes a regeneration process. The solvent, now loaded with captured CO_2, is heated to release the CO_2 molecules from the solvent. This step generates a concentrated CO_2 stream that can be further processed for storage or utilization. The process of releasing CO_2 from the solvent requires energy. Typically, solvent regeneration is achieved by applying heat, either through direct heating or by using steam. The regenerated solvent, now free of CO_2, is then recycled back to the absorber column for further CO_2 capture.
3. **Oxy-Fuel:** This approach involves using pure oxygen for fuel combustion instead of air. This results in a flue gas containing mainly CO_2 and H_2O, which can be more easily separated to produce a high purity CO_2 stream. Cryogenic cooling technology is required to separate the nitrogen from the ambient air in order to obtain pure oxygen, although research is underway into “membranes” that could separate the gases. Additionally, flue gas from the combustion products is re-routed back and mixed with the initial oxygen in order to reduce the temperature at which the fuel burns. This is to reduce it to a level that current turbine materials can tolerate, whether in new or existing plants

Figure 3.1 depicts the variety of technologies available for pre-combustion and post-combustion processes for CO_2 separation and capture from gaseous mixtures like syngas or flue gas. Among the mature capture technologies are first-generation amine chemical solvents such as Monoethanolamine (MEA), and physical absorption solvents like Selexol and Rectisol. However, it is important to acknowledge that physical solvents require a substantial amount of electricity for compressing the source gas stream due to their operation at elevated pressures [45].

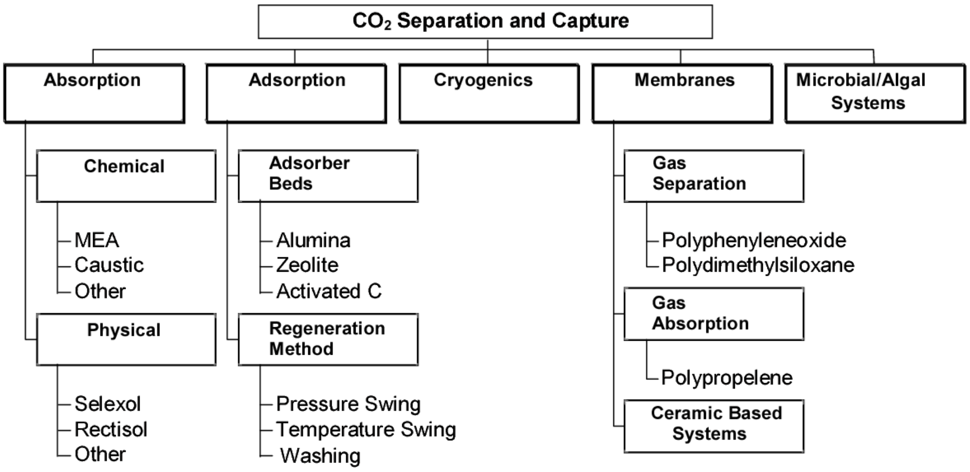

Figure 3. 1. Technology options for CO2 separation and capture.

Credit: Environmental Science and Technology [40,46].

The choice of the appropriate technology depends on the characteristics of the flue gas flow, primarily determined by the power plant technology. In Poland, most power plants are conventional combustion-based plants, producing flue gases that are dilute CO2 streams due to the high nitrogen content of the combustion air. Furthermore, in compliance with the EU CCS Directive, every new combustion plant with a rated electrical output of 300 megawatts or more must undergo an assessment for CCS-readiness. Notably, among Polish combustion plants commissioned after the directive's implementation, at least three units are identified as CCS-ready: one 1075 MW hard coal-fired unit in Kozienice power station (commissioned in 2017), two 905 MW hard coal-fired units in Opole power station (commissioned in 2019) and one 910 MW hard coal-fired unit in Jaworzno power station (commissioned in 2020). Additionally, the 858 MW unit in Bełchatów, associated with the abandoned Bełchatów CCS demonstration project, remains ready for CCS installation development. Moreover, the PEP 2040 CCU/CCS emphasizes this technology as instrumental in the gradual reduction of coal's share in the Polish energy mix, affirming that every Polish coal power plant is CCS-ready[39,40].

This project aims to address post-combustion CO2 capture in pulverized coal-fired plants, which are widely used for power generation in Poland. Specifically, the focus is on utilizing chemical absorption systems for this purpose. The modelling framework utilized in this project is built up on IPSEpro. The proposed CCS method within this model involves the implementation of either aqueous monoethanolamine (MEA). These methods are integrated into a thermal-steam cycle model for the power unit, coupled with a post-combustion capture unit designed for CO2 capture. By combining these components, the project seeks to optimize the capture process and its integration into existing power generation systems.

In the Polish context, advancements have been made in carbon capture and storage (CCS) technologies. Two notable projects, namely the Bełchatów project developed by PGE S.A. (Polish Energy Group – PGE) and the Pilot carbon capture plant at the Łaziska Power Station, have assess the use of post-combustion amine-based chemical absorption technology to achieve efficient CO2 capture. The Bełchatów project planned to utilize the Advanced Amine Process (AAP), with a carbon capture efficiency estimated to be above 85%, which means that 1.8 million tonnes of CO2 per annum could be captured [47]. Similarly, in 2013 the pilot carbon capture plant at the Łaziska Power Station, developed in collaboration between Tauron Wytwarzanie S.A., the Institute for Chemical Processing of Coal (Instytut Chemicznej Przeróbki Węgla – IChPW), and Silesian University of Technology (Politechnika Śląska), also used the post-combustion amine-based chemical absorption technology [40].

These projects exemplify the ongoing efforts in Poland to leverage amine-based chemical absorption technology for effective CO2 capture. Through the capture of substantial amounts of CO2 emissions, these initiatives play a vital role in reducing the environmental impact associated with coal-fired power generation. The successful implementation of these technologies will represent a significant milestone in Poland's journey towards cleaner energy production. It will demonstrate the country's commitment to advancing CCS solutions and achieving large-scale CO2 capture in a post-combustion setting.

3.1.2 Transportation/Infrastructure

Pipelines serve as the primary method for transporting the substantial volumes of CO2 involved in CCS projects. Globally, extensive pipeline networks already exist for the transportation of various gases, including carbon dioxide, spanning kilometres in length. For smaller quantities of CO2, truck and rail transport can be utilized. Some project sites employ trucks to transport CO2 from capture sites to nearby storage locations. However, considering the significant amounts of CO2 that CCS aims to sequester over the long term, it is expected that truck and rail transport will have a limited role. In certain regions, shipping by vessel can be a viable alternative. In Europe, for example, small-scale CO2 transport has already been undertaken, with ships transporting approximately 1,000 tons of food-grade CO2 from major emission sources to coastal distribution terminals [48].

At a Large-scale CCS requires the development of a transport infrastructure on a scale comparable to that of the current hydrocarbon infrastructure, capable of transporting hundreds of millions of tons of CO2 every year – from power plants and industrial sectors to suitable storage sites, EU-wide. If different CO2 sources are located in close proximity, they can share both CO2 transport and storage infrastructure, thus benefitting significantly from economies of scale. Such clusters will also act as the launch pads for wider deployment by providing practical experience in the design and operation of shared CO2 infrastructure. For this matter building a trans-European CO2 transport networks for the development of the CO2 transport infrastructure involving the construction of numerous pipelines linking CO2 sources with sinks, it is a cornerstone, however this implies that pipelines will be constructed no just in the context of individual CCS projects, but rather linking it to a network between emitters from different sectors sharing transport (pipelines, shipping, fleets) and storage infrastructures, which could decrease the risk associated for the investment, therefore incentivizing stakeholders and governments to take part in it and speed up its construction.

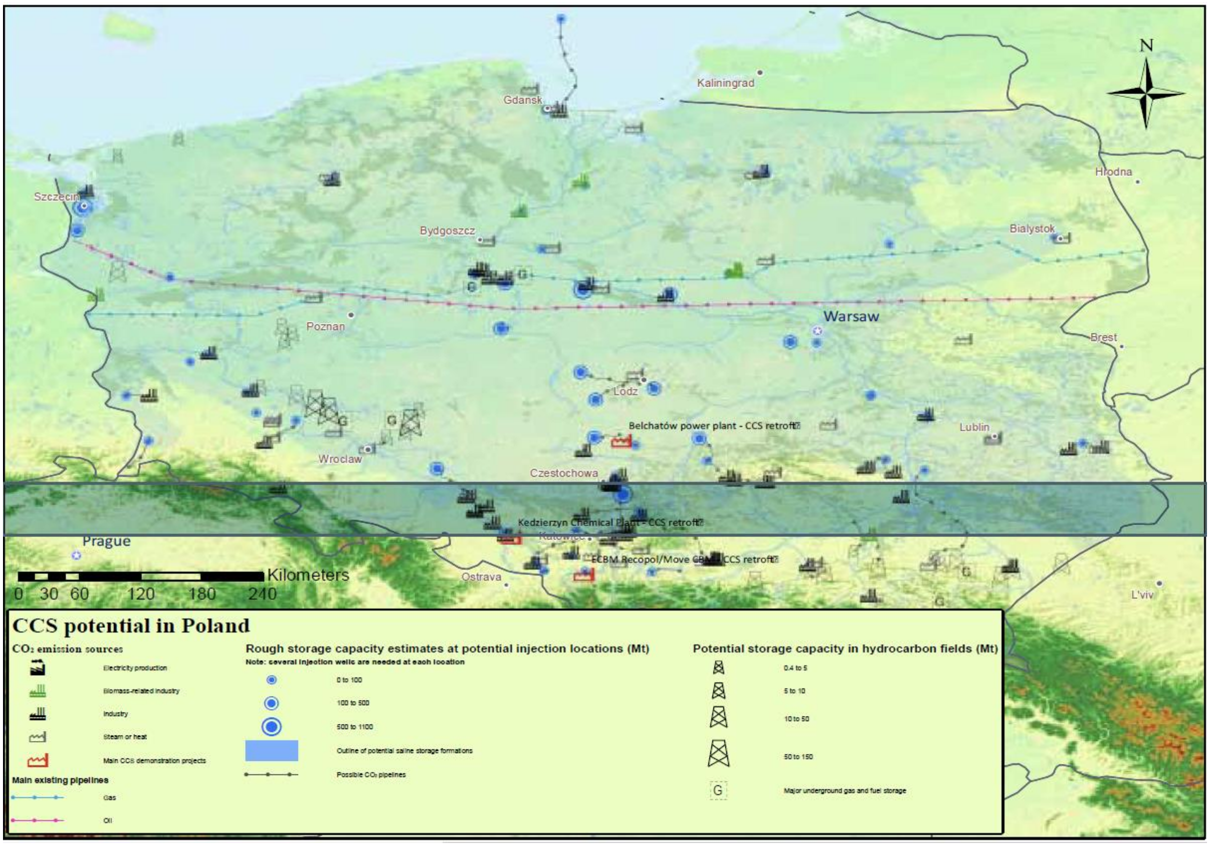

Figure 3. 2. Possible future infrastructure for CO 2 storage and transport in Poland.

Credit: Bellona environmental CCS [38].

The Bellona Institute has presented an insightful map (Figure 3.2), illustrating the potential infrastructure for a comprehensive value chain in Poland. This possible infrastructure would connect emission points to storage sites through a network of CO2 pipelines. The map highlights the proposed transport corridors, potential CO2 injection points, and suitable storage formations. According to Bellona, the transportation of the majority of CO2 can be facilitated by 32-inch pipelines, with a transport capacity exceeding 20 metric tons per year, for distances shorter than 180 km. In addition, the Upper Silesia region (including the industrial areas of Katowice, Rybnik and Będzin) is considered a promising candidate for the initial local pipeline network, as it is home to 16 coal mines, 10 large power plants, coking plants and metallurgical industry, and also has potential CO2 storage sites, including one aquifer and three coal seams, with estimated storage capacities [49]. Aditionally, in the realm of infrastructure and value chains, Poland has actively participated in the European Union's efforts to develop cross-border carbon dioxide transport networks. In 2021, Poland submitted a proposal for the Poland EU CCS Interconnector to be included in the fifth EU list of Projects of Common Interest. This project aims to establish an open access multi-modal CO2 Export Hub from Gdansk and its surrounding areas. The primary objective is to connect major industrial CO2 emitters in Gdańsk and the hinterland to geological carbon storage sites in the North Sea basin. Liquid CO2 shipping will be utilized for this purpose. The project envisions the transportation of 2.7 million tonnes of CO2 per year between 2025-2030, and 8.7 million tonnes of CO2 per year between 2030-2035. The establishment of this effective and efficient cross-border CCS network and value chain will enhance the capacities of all stakeholders involved. It will result in reduced costs through economies of scale, while also improving the reliability and robustness of the European CCS value chain as a whole.[50]

3.1.3 Injection/Storage

The storage of CO2 plays a vital role in ensuring the viability and success of CCS as a comprehensive solution. Without effective CO2 storage mechanisms, the potential of CCS cannot be fully realized. This section will focus exclusively on underground reservoirs, including Saline Formations, Depleted Oil and Gas Reservoirs, and Enhanced Oil Recovery (EOR) sites. Injecting CO2 into deep geological formations requires a carefully selection of sites to secure the underground storage of CO2 for long periods of time. At depths below about 800–1000 m, CO2 is in a supercritical state exhibiting a liquid-like density that provides the potential for storage capacity within the pores of sedimentary rocks[51]. Computational model tools, such as IECM from the University of Wyoming (UW) helps to understand the dynamics behind the performance, emissions and costs of fossil fouled–fired plants using advanced technologies such as CCS.

When carbon dioxide reaches a supercritical state, the density of carbon dioxide increases rapidly at a depth of about 800 meters, opening up the possibility of efficient use of underground storage space in the pores of sedimentary rocks. In Figure 3.3, the bubbles and droplets represent the relative volume occupied by CO2, which decreases significantly with depth at a depth of 800 m. Density and specific volume remain almost constant at depths below 1.5 km [51]. CO2 in the supercritical phase possesses properties of a liquid but flows as a gas. Essentially, CO2 is required to be stored at this state due to its higher density, reducing the buoyancy differential between CO2 and in situ fluids. Carbon dioxide is captured in place in the reservoir by one or more of five basic trapping mechanisms: (1) stratigraphic, (2) structural, (3) residual, (4) solubility and (5) mineral trapping. Initially, stratigraphic or structural trapping, alone or combined, are the dominant mechanisms. After injection, buoyancy causes CO2 to rise and get trapped at the top by an impermeable caprock, confining it within the reservoir. In structural trapping, impermeable rocks confine CO2 through faulting or other geological mechanisms. Residual trapping prevails after injection ceases. Some CO2 is trapped in pore spaces due to water's capillary pressure. Water from surrounding rocks migrates back, immobilizing the CO2. Over shorter timescales, CO2 dissolves into saline formation waters (solubility trapping). CO2-rich waters sink to the base of the deep saline formation. Over longer timescales, CO2 may chemically react with reservoir rocks, forming stable minerals like carbonates [52].

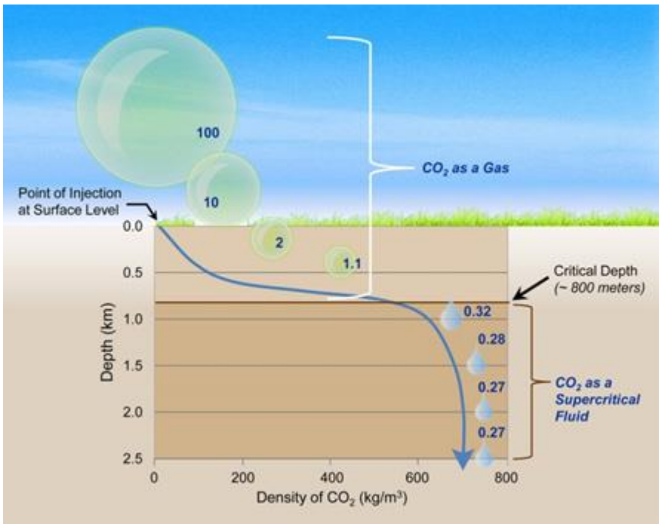

Figure 3. 3. Variation of CO2 density with depth, assuming hydrostatic pressure and a geothermal gradient of 25°C km–1 from 15°C at the surface.

Credit: IPCC Special Report on Carbon Dioxide Capture and Storage [51].

The selection of a geological site for CO2 storage must met three primary criteria. First, it should have sufficient **capacity** with ample pore volumes to store large quantities of CO2. Second, the site must possess high **injectivity**, characterized by high permeability, ensuring wellhead pressure is available to maintain the desired injection rate. Lastly, effective **containment**, required competent cap rocks and sealed faults to prevent the escape or leakage of injected CO2 into the atmosphere or groundwater over long periods due to the lower density of CO2 gas compared to reservoir fluids. The following geological storage locations showcased in Figure 3.4, are the most likely to meet the injection requirements [53]:

1. **Saline Formations:** Saline aquifer formations are the most suitable geological option for CO2 storage due to their vast storage capacity. The high salinity of these aquifers renders them unsuitable for other purposes such as industrial or agricultural use.
2. **Depleted Oil and Gas Reservoirs:** Depleted oil and gas reservoirs possess the necessary characteristics for CO2 storage and have been successfully utilized for geologic sequestration. However, a potential cause for concern is the integrity of the wells, which were filled with mud and plugged with cement after the hydrocarbon reserves reached the end of their production. If not properly maintained, these wells could create pathways for CO2 leakage. In Poland there are no fields large enough to accommodate largest power plant emissions in a single hydrocarbon field.
3. **Enhanced Oil Recovery (EOR):** CO2 is employed for enhanced oil recovery (EOR) in mature oil fields. During this process, around 50-70% of the injected CO2 returns with the extracted oil. However, this can be separated and re-injected into the hydrocarbon reservoir, minimizing operational costs and serving as a means of CO2 storage.

4. **Deep unmineable coal beds:** CO2 can used to help extract methane gas from coal seams in a process called enhanced coal bed methane (ECBM) recovery. Coal beds have numerous cracks and fractures that allow gas molecules to move through and release trapped methane. By injecting CO2 into the coal seams, it helps to loosen and release the tightly held methane, making it easier to recover, however this technology is not yet fully matured.

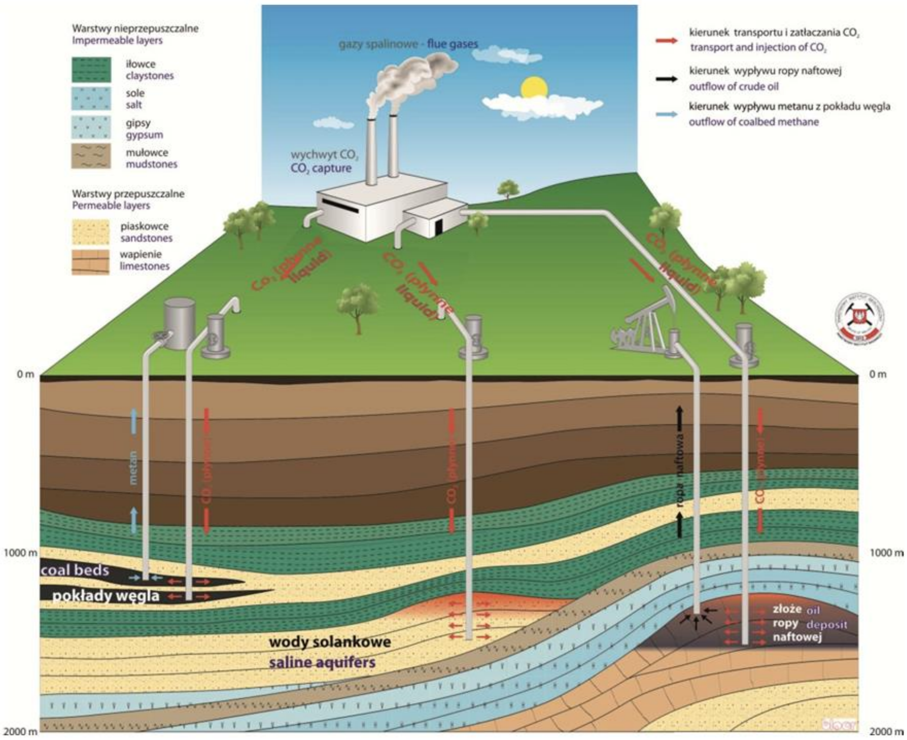

Figure 3. 4. Ideological scheme of geological sequestration of CO2 in Polish Conditions.

Credit: Państwowy Instytut Geologiczny – Państwowy Instytut Badawczy (PIG-PIB) [54].

The assessment of potential storage sites in Europe was conducted through the EU GeoCapacity project, over a 3-year period from 2006 to 2008. The project covers most of the sedimentary basins in Europe suitable for CO2 geological storage, oil and gas fields (including EOR) and coal fields (including ECBM) located in deep saline aquifers in EU Member States. In Poland, the estimates revealed that the largest storage capacity exists in deep saline aquifers, with a capacity of **1,761 Mt**. This is followed by hydrocarbon fields with a capacity of **764 Mt** and coal seams with a capacity of **415 Mt**. These are only conservative estimates as they give **probably the most realistic** picture of the storage capacity achievable in Europe [55].

Between 2008 and 2012, the Polish Ministry of the Environment's national program "Assessment of strata and structures for safe geological storage of CO2, including a monitoring program" covered almost the entire territory of Poland and the Baltic Sea economic zone, including the suitability of formations and structures suitable for CO2 storage. The regional study covers the whole of Poland (Figure 3.5); in particular, the study of saline aquifers (indicated by Roman numerals I-VIII) as well as depleted and uneconomical oil and gas fields and deep unminable coal deposits in eight regions of the country: I(Bełchatów), II (Upper Silesian Coal Basin (USCB))), III (Masovia), IV (Carpathian Overthrust/Subcarpathian), V (Lublin and Podlaskie regions), VI (Greater Poland – Kuyavian), VII (Northwest Poland) and VIII (Łeba-Baltic Sea, including offshore area, and NE Poland).

Figure 3. 5. State of knowledge about possibilities of CO2 geological storage in Poland.

Credit: Państwowy Instytut Geologiczny – Państwowy Instytut Badawczy (PIG-PIB) [54].

The results for the estimates are related to the **static, effective storage capacity** of geological formations and structures based on different categories established in the EU GeoCapacity project. The (very roughly) estimated potential for storage in saline aquifers is approximately **14,495 Mt**, spread across structures/sites (I, II, III, IV, V, VI, VII, VIII) in the formations of Paleozoic, Mesozoic (with a significant potential in the Jurassic), Cenozoic (Miocene), Lower Cretaceous, and regional Cambrian and Carboniferous aquifers. The potential for storage in hydrocarbon structures ranges from **784 to 1,021 Mt**, predominantly in depleted gas fields, with oil fields accounting for less than 10% of the total potential. The potential for storage in coal beds is estimated to be between **20 and 100 Mt,** with 20 Mt considered for possible exploration permit areas within the USCB and 100 Mt for the entire USCB area, encompassing coal seams at depths of 1-2 km[54]. The whole potential is in theory enough for half a century of industrial emissions covered by the ETS in Poland (which is about 191 Mt CO2 per year [35]).

3.2. State of the Art

There are currently 30 large-scale CCS facilities in operation globally, with 11 more under construction and 155 (2 suspended) in different stages of development, as per Figure 3.6 from the Global CCS Institute. The leadership, is led by North America that accounts for 13 CCS projects in the USA and 5 in Canada, whereas in Europe there are 5 operating facilities: 2 in Norway, 1 in Hungary and 1 in Iceland[56]. According to the independent Global CCS Institute (GCCSI), the current storage capacity is about 40 - 43 million tons of CO2 per year. Including all new CCS projects that have been announced; eventually, this number is expected to increase up to 244 Mtpa[30].

However, to mitigate the hardest effects on climate change and support Europe's path to a climate neutral economy, the installed capacity of CO2 must grow from 244 Mtpa to billions of tons per year. Nowadays, operational facilities, on average, can inject just over 1 Mtpa CO2[30]. As low-carbon Hydrogen is playing an increasingly important role in the strategies of European countries who want to decarbonize key sectors like transport, industrial processes and domestic heat, several CCS projects incorporate the production of hydrogen through steam methane reforming of natural gas, while capturing and storing the associated CO2, such as the Quest CCS facility in Canada, operating since the end of 2015, where 4 million tons of CO2 had been captured and safely stored from the SMR process for hydrogen production. "Next wave" facilities based around CCS hubs and clusters have taken advantage of the fact that many emissions intensive facilities (both power and industrial) tend to be concentrated in the same areas. Hubs and clusters significantly reduce the unit cost of CO2 storage through economies of scale and offer commercial synergies that reduce the risk of investment. They can play a strategically important role in climate change mitigation[57].

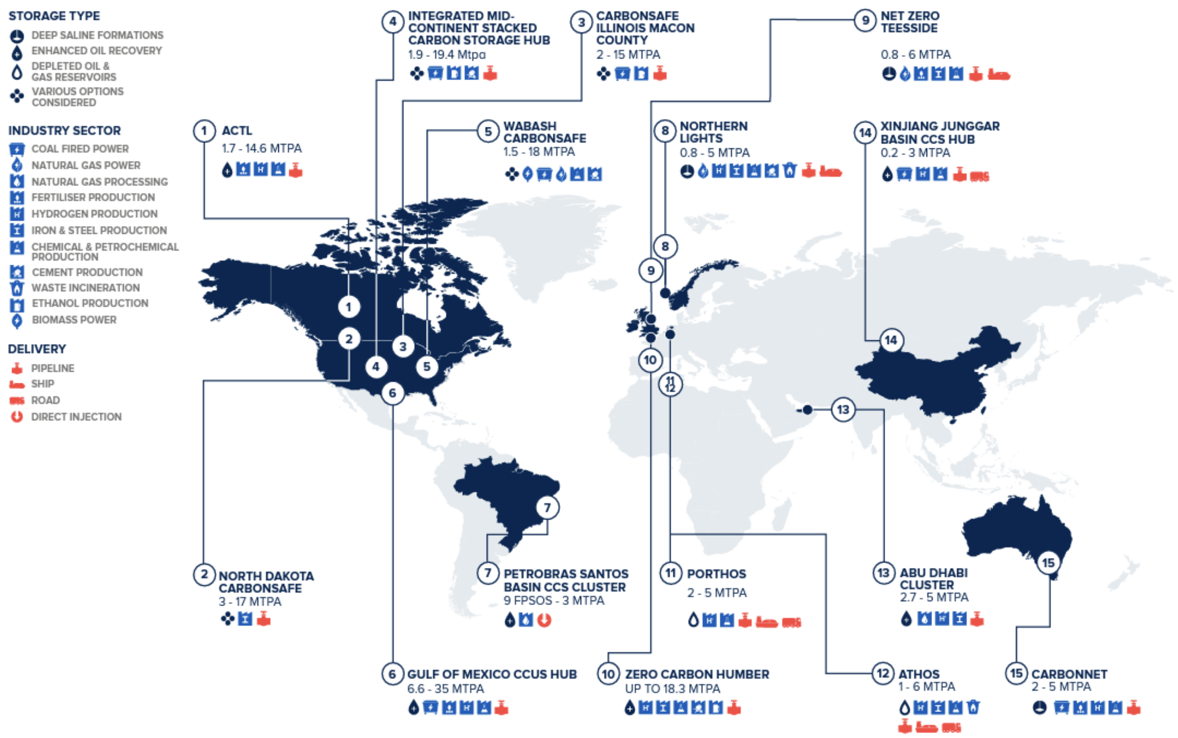

Figure 3. 6. CCS Hubs and Cluster globally.

Credit: Global CCS Institute [57].

These facilities showed that million-ton CO2 injection rates at multi-million-ton storage sites were possible. Today, deep saline formations are the most common type of CO2 storage reservoir across all storage facilities (over 150) at all stages of development from operational through to early development phases. CO2 storage facilities targeting deep saline formations are most substantial in North America and the North Sea. Storage in depleted oil fields is also set to become more common, for example in the UK and in Australia and Southeast Asia. Among all the long-term storage of CO2 in geological formations, together they are estimated to have a global storage capacity of **13,954 Gt CO2**[58], therefore with current world energy-related CO2 emissions of about 36.5 Gt CO2/year[5] there is sufficient storage capacity for CCS to play a major role in emissions abatement.

CCS Project activities were undertaken in Poland, involving two demonstration projects in 2008. The first project took place at Bełchatów Power Plant, and the second at Kędzierzyn (polygeneration project). Unfortunately, both projects were ultimately abandoned due to financial difficulties. The Bełchatów project had made significant progress before its discontinuation. The plan was to construct a full-scale capture plant with a capacity of 1.8 Mt/year, utilizing Alstom's advanced amines technology. This plant would have been installed at the new 858 MWe lignite-fired unit. The project received an EU EEPR grant from the European Commission and was also submitted to the EU NER 300 programme. However, due to challenges in finalizing the financial plan, the project was halted in 2013. Nevertheless, the lignite-fired unit was designed to be CO2 capture-ready, and the project had included provisions for

CO_2 transportation via a pipeline and associated infrastructure to transport compressed CO_2 from the capture plant to the storage site. The storage component of the project involved injecting pressurized CO_2 into deep saline aquifers for permanent storage.

The Polygeneration project, centered at the Kedzierzyn Chemical Plant, aimed to establish a zero-emission facility combining power engineering with chemical production. It consisted of a coal gasification plant for producing synthesis gas used in chemical production (methanol and hydrogen), as well as the generation of high-pressure steam for co-generation of electricity and heat. Additionally, the project included a second plant integrated with gas and steam turbines in an IGCC (integrated gasification combined cycle) configuration, with CO_2 removal before combustion of the syngas in the gas turbine. The captured CO_2 was intended to be transported and stored in selected geological structures of the Mesozoic basin. However, the Kędzierzyn polygeneration project was abandoned in 2011[49].

However, in Poland, several legal criteria may prevent the rapid implementation of CCS initiatives. These criteria must be met before scenarios for CCS demonstration projects can be considered, as outlined in legislation and regulations. With regard to the implementation of CCS, relevant legal frameworks include the Law of 27 September 2013, the Geology and Mines Act and Energy Act 89. Specific aspects of these legal considerations are detailed below[40]:

a) Minimum capacity threshold:
   - 250 MW (applies to power plants),
   - 500 kilotonnes per year (kt/y) stored CO_2 (applies to industrial plants);
b) Each project has to implement the full chain (capture, transport and storage);
c) Each demonstration project must implement heat integration for the capture component of the process;
d) The capture rate has to be at least 85% of CO_2 from the flue gases to which capture is applied;
e) Each project has to contain an independent research block related to safety of storage sites and improvement of monitoring technologies especially in the field of brine migration, its possible pathways and impacts;
f) The project is implemented for the purpose of verifying: effectiveness and usefulness of application of the technology of carbon dioxide capture and storage in the scope of carbon dioxide emission limitation, safety of application of the technology of carbon dioxide captures and storage for human health and life and for the environment, the need and grounds for admitting to application the technology of carbon dioxide captures and storage on an industrial scale.

The Act also defines which areas are admissible for CCS and only offshore projects can be developed, which currently includes one depleted hydrocarbon field with surroundings in the Baltic Sea within the Polish exclusive economic zone [40].

3.3. Cost and Performance Baseline for Fossil Energy Plants

Integrated Gasification Combined Cycle (IGCC) plants offer a more efficient and cleaner alternative to traditional coal-fired power plants, which use a combination of gasification technology and a combined cycle system to convert a variety of carbon-based feedstocks into electricity. The key feature of IGCC plants is the gasification process, which converts the solid feedstock into a synthesis gas (syngas) comprising hydrogen, carbon monoxide, and other gases. This syngas is then used to generate electricity through a combined cycle. IGCC plants can be operated both with and without CO2 capture. In the scenario when the IGCC plant use CO2 capture. Table 3.1 and 3.2 show a comparison of IGCC systems without and with CO2 separation, according to the National Energy Technology Laboratory (NETL)[59].

Table 3. 1. Comparison of technological indicators for IGCC plants with and without CO2 capture.

Indicator	Unit	Shell		Chicago Bridge and Iron E-GasTM FSQ		General Electric Power	
		IGCC	IGCC+CCS	IGCC	IGCC+CCS	IGCC	IGCC+CCS
Gross power	MWe	765	696	763	742	765	741
Own demand	MWe	125	177	122	185	131	185
Net power	MWe	640	519	641	557	634	556
Coal flux	kg/s	54,86	58,88	57,50	60,75	58,56	60,80
Fuel power	MWt	1 488	1 597	1 560	1 648	1 588	1 649
HHV net efficiency	%	43,0	32,5	41,1	33,8	39,9	33,7
Raw water intake	m3/h	936	1 153	989	1 179	1 089	1 251
Process water discharge	m3/h	209,3	244,0	214,3	250,4	234,5	254,9
Raw water consumption	m3/h	727,7	909,1	774,7	929,1	854,9	996,3
CO_2 capture level	%	0	90	0	90	0	90
Gross CO_2 emissions	kg/MWh	602,4	73,0	630,9	69,4	633,2	68,5
Net CO_2 emissions	kg/MWh	720,3	97,5	751,6	92,5	764,3	91,17

The information provided in Table 3.1 offers insights into various indicators comparing IGCC technologies with and without CCS. The data is associated with three companies: Shell, E-Gas™, and General Electric (GE) Power. Shell and GE Power IGCC technologies achieve the highest gross power generation at 765 Mwe each, but Shell has the lowest gross power generation at 696 MWe when using CCS. This is reflected in the HHV Net Efficiency, where Shell has the highest net efficiency before CCS implementation at 43.0% and 32.5% (10.8% penalty), even though among the options, Shell's IGCC technology has the lowest CO2 emissions per kg/MWh. General Electric Power's IGCC technology has the lowest net efficiency before CCS implementation at 39.9%, but its energy penalty is the lowest one at 6.2%. These results show that the implementation of CCS results in an energy penalty for all technologies, reducing their net efficiency. Shell's technology incurs the highest energy penalty, which might be due to the complexities of integrating CCS into its setup. However, CCS implementation enables these technologies to achieve a 90% CO2 capture rate, which is a significant step toward reducing greenhouse gas emissions.

Table 3. 2. Comparison of economic indicators for IGCC plants with and without CO2 capture.

Indicator	Unit	Shell		Chicago Bridge and Iron E-Gas™ FSQ		General Electric Power	
		IGCC	IGCC+CCS	IGCC	IGCC+CCS	IGCC	IGCC+CCS
Total cost	$2018/kW	5.397	8.810	4.799	7.370	5.414	7.446
LCOE	$2018/MWh	105,8	166,5	97,5	143,1	107,9	144,2
Fixed costs	$2018/MWh	20,0	31,9	18,0	26,9	20,0	27,2
Variable costs	$2018/MWh	13,6	22,3	12,6	19,4	14,1	19,3

To analyse whether the implementation of CCS (Carbon Capture and Storage) in an IGCC plant is profitable, it is important to consider the key indicators provided in the Table 3.2 for the year 2018, considering Shell, E-Gas™, and General Electric Power technologies. Total Cost indicates the cost of constructing the power plant per kilowatt of capacity. Shell IGCC+CCS has the highest total cost at $8,810/kW, followed by General Electric Power's IGCC+CCS at $7,446/kW. LCOE (Levelized Cost of Electricity) represents the cost per unit of electricity generated over the plant's lifetime, factoring in all costs including construction, operation, and maintenance. Again, among the options Shell IGCC+CCS has the highest LCOE at $166.5/MWh, followed by General Electric Power's IGCC+CCS at $144.2/MWh. Fixed Costs represent the portion of costs that remain constant regardless of the amount of electricity generated. All the technologies have similar fixed costs before CCS implementation, ranging from $18.0/MWh to $20.0/MWh. After CCS implementation, fixed costs increase for all technologies, with Shell IGCC+CCS having the highest fixed costs at $31.9/MWh.

The scope of the project is a NGCC Power Plant type integrated with a Post Combustion Carbon Capture Storage (PCCS) process. A combined cycle power plant (CCPP) consists of a gas turbine and a steam turbine to generate electricity. After the gaseous fuel is burned in the gas turbine combustor, the flue gas passes through a heat recovery steam generator (HRSG), which uses the steam turbine to extract heat and generate additional electricity, by utilizing the thermal energy in the exhaust gas it also reduces the waste of energy improving the power production efficiency up to 65% [60]. NGCC technology is known for its highest power generation efficiency. The solvent used in PCCS technology is an aqueous amine solution that reacts with the flue gas and absorbs carbon dioxide, which is then treated and separated. This thesis presents the results of an energy analysis of a post-combustion carbon capture process integrated into a combined cycle gas-fired power plant.

Table 3.3 shows the performance parameters for a NGCC without and with a PCCS system. For the latter is used a CANSOLV CO2 Shell technology for carbon dioxide (CO2) recovery, which utilizes a regenerable amine and has been used in the Saskpower Boundary Dam facility in Canada, capturing more than 5 million tonnes of CO2. The use of TEG in the compression process suggests that TEG might be utilized to assist in managing the temperature and moisture content during compression. TEG can absorb moisture and help maintain stable compression conditions.

Table 3. 3. Energy characteristic parameters of gas-steam power units

Parameter	Without CO_2 capture installation	With CO_2 capture installation
Gas turbine	2 F-class gas turbines powered by natural gas	
Recovery boiler	2 parallel three-pressure recovery boilers	
Steam turbine	1 three-stage steam turbine (16,5 MPa /585 °C / 3,5 MPa / 585 °C)	
CO_2removal plant	-	Cansolv (2,9 MJ/kg for regeneration purposes)
CO_2 compression installation	-	8-stage with Triethylene Glycol (TEG)
Gross power of gas turbine, MWe	477	477
Gross power of steam turbine, MWe	263	213
Total gross power, MWe	740	690
Power system's own power requirements, MWe	14	16,3
Captive power of CCS plant, MWe	0	27,7
Net energy efficiency, % (up to LHV)	59,4	52,8
Natural gas flux, kg/h	932 72	
Chemical energy of fuel, MWch (up to LHV)	1.222,94	
Specific emission of CO_2, kg/MWh	For gross energy: 336 For gross energy: 342	For gross energy: 36 For gross energy: 39
Flue gas outlet temperature to chimney °C	82	31

Regarding power generation is evident that the power plant with CO2 capture has a slightly lower gross power output (690 MWe) compared to the one without CO2 capture (740 MWe). This reduction is primarily due to the energy requirements of the CO2 capture process itself, which affected directly the energy efficiency, given that the power plant without CO2 capture has a higher net energy efficiency (59.4%) compared to the one with CO2 capture (52.8%). This difference is also due to the energy consumption of the CO2 capture and compression processes. On the other hand, CO2 capture significantly reduces specific CO2 emissions (36 kg/MWh) compared to the one without CO2 capture (336 kg/MWh).

The 8-stage compression indicates that the CO2 compression process is divided into eight distinct stages as shown in Table 3.4. Each stage involves increasing the pressure of the CO2 gas and after every stage CO2 cooled down to the temperature 30-40 C. Multi-stage compression is often used to achieve higher compression ratios while minimizing temperature rise, which can be important for maintaining efficiency and avoiding excessive heat generation during compression

Table 3. 4. CO2 compression Stages

Compression stage	Output pressure, MPa	Compression ratio
1	0,26	2,28
2	0,59	2,28
3	1,22	2,21
4	2,51	2,07
5	3,97	1,66
6	6,34	1,60
7	9,87	1,56
8	15,27	1,55

Table 3.5 presents the economic parameters for installations both with and without CCS. The Total Plant Cost (TPC) represents the cost of constructing the power plant per kilowatt of installed capacity. The option with CO2 capture has a significantly higher TPC, which is expected due to the additional costs associated with implementing CO2 capture technology. TPC without CO2 capture is $780/kW while With CO2 capture is $1,984/kW. Total Annual System Cost (TASC) Without CO2 capture is $1,040/kW while With CO2 capture is $2,635/kW. TASC accounts for both the capital costs and operating costs of the power plant per kilowatt of installed capacity.

Table 3. 5. Economic characteristic parameters of gas-steam power units.

Parameter	Without CO_2 capture installation	With CO_2 capture installation
TPC, $2018/kW	780	1 984
TPC, $\$_{2018}$	566.971	1.281.324
TASC, $\$_{2018}$/kW	1.040	2.635
TASC, $\$_{2018}$	755.721	1.701.831
Fixed operating expenses, $\$_{2018}/kW_{net}$	26,8	63,9
Variable non-fuel operating costs, $\$_{2018}/MWh_{net}$	1,705	5,633
LCOE	43,3	74,4
LCOE components, %: investment operational fuel CO_2 transport and storage	 23 12 65 0	 34 20 43 5

The option with CO2 capture again has a higher TASC due to increased capital and operating expenses. Besides, fixed operating expenses, as well as the variable non-fuel operating costs with CO2 capture option has substantially higher costs due to the energy-intensive nature of the capture and compression processes. In addition, for the option with CO2 capture, a larger percentage of the LCOE is allocated to investment, operational, and fuel costs, reflecting the increased complexity and energy consumption of the CO2 capture process. The percentage allocated to CO2 transport and storage is also significant, highlighting the additional expenses associated with managing the captured CO2.

Based on the provided indicators, it can be said that the implementation of CCS generally leads to increased costs across all categories (total cost, LCOE, fixed costs, and variable costs). Among the options presented, none of the technologies with CCS achieve a lower LCOE compared to their non-CCS counterparts. This indicates that the implementation of CCS adds cost to the electricity generation process. Whether CCS implementation is profitable depends on various factors, including: <u>1. Carbon Pricing:</u> If there are stringent carbon pricing mechanisms or regulatory incentives in place, the reduction in CO2 emissions through CCS could potentially offset the increased costs. <u>2. Long-Term Energy Market Conditions:</u> If electricity prices are expected to rise in the long term, the higher LCOE associated with CCS might become more competitive over time. <u>3. Policy Support:</u> Government policies, subsidies, and incentives for clean energy technologies can influence the economic viability of CCS implementation. <u>4. Environmental Goals:</u> Companies committed to reducing their carbon footprint and meeting sustainability targets may prioritize CCS despite the added costs.

CCS will become more economically viable as the cost of renewable energy continues to fall and the price of carbon emissions rises. In the short term, CCS projects should prioritize economies of scale, moving from individual standalone CCS projects to networks or clusters of CCS facilities to enhance their economic feasibility. These clusters, with shared transport and storage infrastructure lower costs and risks making it more appealing to stakeholders. A key challenge is to curb equipment and energy-related costs in the capture and compression phases, which can undermine the viability of projects. Falling efficiency and higher water consumption further contribute to the problem, so addressing these concerns during the capture and compression phases is crucial. Innovations that reduce energy consumption and water requirements can improve minimize operational costs. In addition, integrating CCS with hydrogen and ammonia production can also enhances viability by capitalizing on its value.

Chapter 4

4. Computational Modelling of Built Scenarios

This study chose chemical absorption as the primary post-combustion carbon capture technology because it tends to be more efficient and practical than other combustion-based power plant systems shown in Figure 3.1, as it involves chemical reactions that enhance the overall mass transfer from the gas phase to the liquid phase for diluted systems with low CO2 concentrations, the technology is commercially available, easy to use, and can be retrofitted to existing power plants. The process of CO2 capture consists in using a continuous scrubber system to separate CO2 from a gas stream and two main elements are required: the absorber, where CO2 is absorbed by the sorbent, and the regenerator (or stripper), where the CO2 is released (in concentrated form) and the original sorbent is recovered [61].

Absorption processes are based on thermally regenerable solvent, which have a strong affinity for CO2. They are generated at elevated temperature. The process thus required thermal energy to the regeneration of the solvent. Aqueous monoethanolamine (MEA) is an available absorption technology for removing CO2 from flue gas streams, process simulation and evaluation are essential items to maximize the absorption process performance.

4.1. Case Scenario for CO2 Capture

The process design is based on the standard regenerative absorption-desorption concept, as shown in the simplified flow diagram in Figure 4.1[62]. The flue gas from the power plant enters a direct contact cooler (C1), whose temperature depends on the type of energy source, and is cooled with circulating water to around 40 °C. The gas is then delivered by a gas blower (P1) to overcome the pressure drop caused by the MEA absorber. The gas flows through the packed bed absorber (C2) in counter current to the absorbent (an aqueous MEA solution) which chemically reacts with the carbon dioxide (packed bed columns are preferred over plated columns because they have a larger contact area). The CO2 lean gas enters the water scrubber (C3) where water and MEA vapor and liquid droplets are recovered and returned to the absorber to reduce solvent loss. The treated gas is vented to the atmosphere [62,63].

The rich solvent containing chemically bonded CO2 is pumped through the lean/rich cross heat exchanger (H3) to the top of the stripper where it is heated to a temperature close to the operating temperature of the stripper (110–120° C) and the carbon dioxide lean solution is cooled. The chemical solvent is regenerated in the stripping column (C4) at high temperature (100-140°C) and at a pressure not higher than atmospheric pressure. Heat is supplied to the reboiler (H4) with low pressure steam to maintain regeneration conditions. This results in a loss of thermal energy as the solvent must be heated to provide the heat of desorption required to remove the chemically bound CO2 and generate the steam used as stripping gas. The steam is recovered in the condenser (C5) and returned to the stripper, and the resulting CO2 gas leaves the condenser. Finally, the lean solvent is pumped back to the absorber through a lean/rich heat exchanger (H3) and cooler (H2) to reduce its temperature to absorber level [62,63].

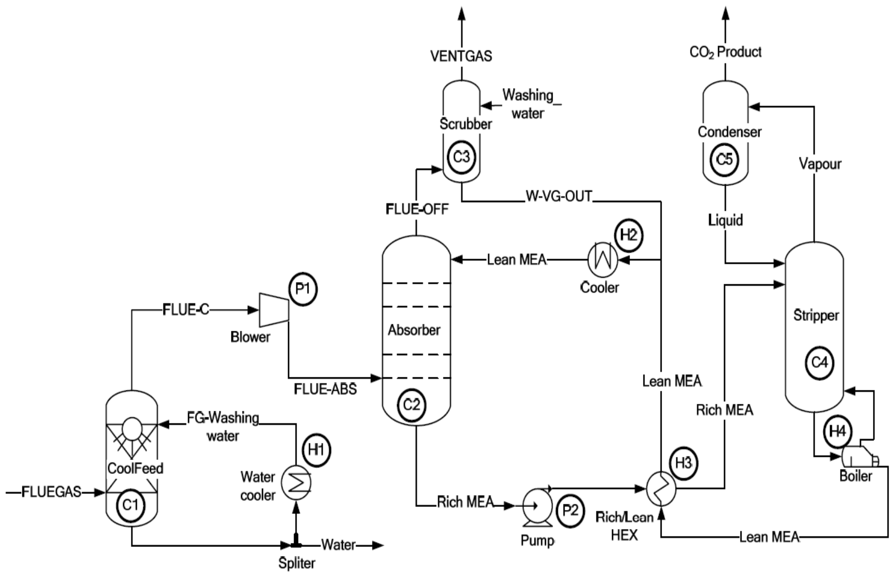

Figure 4. 1. Flowsheet for CO2 capture from flue gases using amine-based system.

Credit: Carbon Dioxide Capture from Flue Gas [62].

Different amines like MEA, MDEA, DEA can be used for absorbing CO2. CO2 is absorbed in the amines in different ways and it follows different mechanisms. These amines are bases and they react with the acid. The amines are soluble in water due to the presence of the alcohol group. The amines can be classified as primary, secondary or tertiary amines according to the different organic group that is attached to the Nitrogen. These different amines react differently, primary and secondary amines have higher heat of absorption and hence react faster compare to the tertiary amine but high amount of energy is required in order to regenerate the primary and secondary amine. CO2 reacts with MEA amine solution to undergo Carbamate formation[64]. There are mainly three compounds, that are active in this system named carbon dioxide (CO2), amine (MEA) and water (H2O). The following equilibrium reactions occur in the bulk of the liquid [65]:

Water hydrolysis: $2\ H_2O \leftrightarrow H_3O^+ + OH^-$

Bicarbonate formation: $2\ H_2O + CO_2 \leftrightarrow H_3O^+ + HCO_3^-$

Carbonate formation: $H_2O + HCO_3^- \leftrightarrow H_3O^+ + CO_3^{-2}$

Amine protonation: $H_3O^+ + R\text{-}NH_2 \leftrightarrow H_2O + R\text{-}NH_3^+$

Carbamate formation: $R\text{-}NH_2 + HCO_3^- \leftrightarrow H_2O + R\text{-}NH\text{-}COO^-$

Here, MEA has been represented as R-NH_2, where “R” stands for HO-CH_2CH_2. The process chemistry is complex, but the main reactions taking place are [64]:

CO_2 Absorption: 2 R-NH_2 (MEA) + CO_2 → R-NH_3^+ + R-NH-COO^- (Carbamate)
MEA Regeneration: R-NH-COO^- +R-NH_3^+ + Heat → CO_2 +2 R-NH_2

The MEA-based absorption process, while suitable for CO2 capture from power plant flue gases, has limitations. The primary challenge includes an energy penalty, as breaking the stable carbamate ion requires substantial heat and energy for sorbent regeneration. Moreover, compressing the captured CO2 for transport adds to the energy requirements, reducing the power plant's net efficiency if extracted internally. Alternatively, constructing a larger power plant becomes necessary to maintain the same net power generation capacity without CO2 capture. Loss of sorbent is another issue, with mechanical, entrainment, vaporization, and degradation causing some sorbent to be unrecoverable. Flue gas impurities like oxygen, sulphur oxides, and nitrogen dioxide react with MEA, forming heat-stable salts that decrease the sorbent's CO2 absorption capacity. Inhibitors can make the sorbent oxygen-tolerant, but SO2 adversely affects the MEA sorbent, necessitating low inlet concentrations to minimize sorbent loss. The formation of heat-stable salts can be treated using a side stream MEA-reclaimer or alternative technologies such as electrodialysis. Corrosion control is crucial for amine systems processing oxygen-containing gases, requiring corrosion inhibitors, lower MEA concentrations, appropriate materials, and mild operating conditions [66].

4.1.1 IPSEpro Software Description

The software used to simulate the performance of the CO2 capture process in the NGCC case study is IPSEpro, which is a tool used for process modeling, simulation, and optimization in the field of energy systems engineering. It stands for Integrated Platform for Smart Energy Simulation and Optimization. It allows to model and analyze various energy systems, including power plants, heat exchangers, boilers, turbines, and more. IPSEpro enables thermodynamic analysis of the carbon capture process. It can simulate the changes in temperature, pressure, and other relevant parameters at various stages of the process. This helps in understanding the energy requirements and efficiency of the capture technology as carbon capture involves complex heat and mass transfer phenomena. IPSEpro also allows modelling these interactions, including heat integration this allows to assess the impact of CO2 capture on the overall plant performance, including changes in power output, energy efficiency, and emissions.

The structure illustrated in Figure 4.2. is a network of appropriately interconnected discrete components including standard libraries, such as the APP-Lib for power plant simulations; the gas-turbines library; and the heat-exchangers library[67]. The advanced power plant library was designed for modelling a wide range of thermal systems including: combined-cycle plants; cogeneration plants; and conventional plants. The software model library includes common components, and users can create custom models using a supplied Model Development Kit (MDK) for specialized tasks.

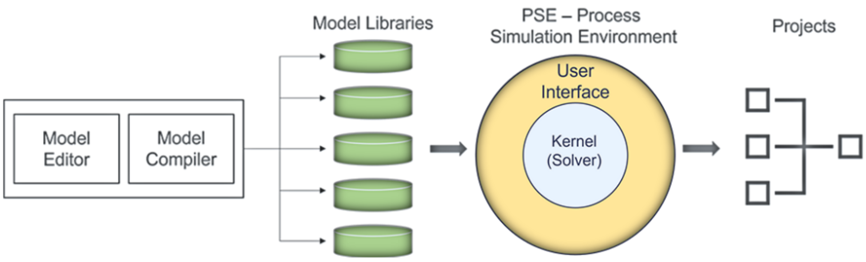

Figure 4. 2. IPSEpro modelling Concept.

Credit: Simtech [68].

Mathematically, the computation of a flowsheet model relies on simultaneously solving mass and energy balances, incorporating specific equations that describe the behaviour of each component through systems of equations[68]. The simulation results depict a steady-state operating point of a plant. Among the thermodynamic equations, a key one is the Ideal Gas Law:

$$PV = nRT \dots\dots\dots\dots (1)$$

Where, P for Pressure, V for Volume, n for Number of moles, R for the Ideal gas constant, and T for Temperature.

In heat transfer, various equations for mechanisms like conduction, convection, and radiation are employed based on the selected heat transfer model. An example is Fourier's Law of Heat Conduction:

$$q = -k * A * \frac{\Delta T}{\Delta x} \dots\dots\dots\dots (2)$$

Where, q for heat transfer rate (W), k for thermal conductivity of the material (in watts per meter-kelvin), A for cross-sectional area for heat transfer (m^2), ΔT for temperature difference across the material (K), and Δx for material thickness (m).

IPSEpro, employs also various equations for mass transfer. A general equation representing mass transfer could be based on Fick's Law of Diffusion, often used for describing mass transfer of a component in a fluid or through a material:

$$J = -D * \partial x \partial C \dots\dots\dots\dots (3)$$

Where, J is the mass flux, D is the diffusion coefficient, C is the concentration of the diffusing component, x is the spatial coordinate.

In summary, IPSEpro provides a comprehensive platform for modeling, simulating, and analyzing carbon capture technologies within energy systems. This facilitates informed decision-making about the implementation of carbon capture in power plants.

4.1.2 Natural Gas Combined Cycle Power Plant Case Study

The Case Study power station, is a 465-MW gas-fired facility. By adopting co-generation principles, the plant not only generates electricity but also harnesses useful heat, maximizing energy utilization and contributing to reduced emissions. The NGCC power plant is a power generation facility that utilizes both gas turbines and steam turbines to produce electricity. The plant operates in two main cycles: the gas turbine cycle and the steam turbine cycle, which are combined to maximize efficiency and power generation. The combination of the gas turbine and steam turbine cycles significantly improves the overall efficiency of the power plant compared to a standalone gas turbine plant. Figure 4.3 shows the general scheme of the NGCC power plant integrated with CCS; the main components are described below:

1. Gas Turbine: The gas turbine subsystem consists of a GE Energy gas turbine fuelled by natural gas, a fuel heater, a protection system, and inlet gas preparation. The subsystem uses a 3-stage turbine and a compressor with 18 (compression ratio). The turbine is equipped with multi burner combustion chambers. The air stream after cleaning is supplied to the compressor with a flow rate (air flow) of 670 kg/s (design data, maximum load). From the compressor, the air enters the combustion chamber assembly, where the combustion of fuel preheated to a temperature (gas temperature) of 200 °C takes place. The high-temperature and high-pressure gases resulting from the combustion expand through the turbine, converting the gas turbine's kinetic energy into mechanical energy to drive the generator, producing electricity. After passing through the turbine rotor system, the exhaust gas is directed to a steam recovery boiler[69,70].
2. Steam Turbine Cycle: The waste heat from the gas turbine cycle is used to generate steam in a heat recovery steam generator (HRSG). The HRSG is essentially a large heat exchanger where water is heated using the waste heat from the gas turbine's exhaust gases. The high-pressure steam produced in the HRSG then enters the steam turbine, where it expands, driving another generator to produce additional electricity. The turbines were mounted on a common take-off shaft with the generator and gas turbine system. The subsystem used 3 levels of steam pressure: high pressure (HP- high pressure), intermediate pressure (IP - intermediate pressure) and low pressure (LP - low pressure), typical use [71–74].
3. Fuel: The composition of natural gas can influence its energy content and combustion characteristics in a NGCC power plant. The high methane content in natural gas, represented as a significant percentage of the composition, contributes to its efficient and cleaner-burning characteristics compared to other fossil fuels like coal or oil. The specific composition of natural gas used in the power plant is carefully monitored and controlled to ensure optimal performance and efficiency of the power generation process. The characteristics of the fuel are described in Table 4.1.

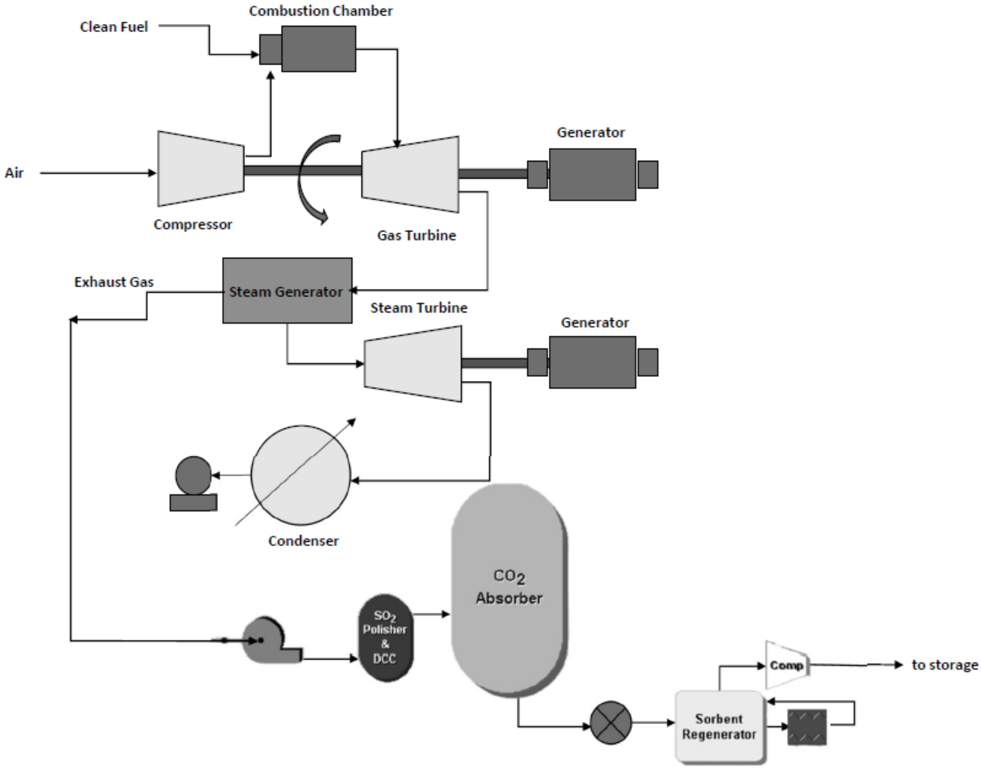

Figure 4. 3. Schematic diagram of the case study NGCC Power Plant integrated with PCCS.

Table 4. 1. Composition of Natural Gas Fuel Used in NGCC Power Plant.

Natural gas components	Molar fraction
CH_4	97,15
C_2H_6	2,0
C_3H_8	0,2
i-C_4H_{10}	0,05
n-C_4H_{10}	0,028
i-C_5H_{12}	0,0023
n-C_5H_{12}	0,006
CO_2	0,1
N_2	0,4

In addition to methane, the fuel also contains varying percentages of other hydrocarbons such as ethane, propane, and butane. Nitrogen and carbon dioxide, as non-hydrocarbon components, are also present, albeit in lower concentrations. By carefully managing and optimizing the natural gas composition, the NGCC Power Plant can achieve the highest possible energy conversion efficiency while meeting environmental standards and regulations.

The CO2 capture and separation system consists of the following process equipment:

Direct Contact Cooler: Flue gases from power plants can reach 60°C (in coal-fired power plants equipped with SO2 wet scrubbers) up to over 550 °C (for natural gas single cycle power plants). It is best to cool the flue gas to around 45-50°C to improve the absorption of CO2 by the amine adsorbent, minimize the adsorbent loss and avoid excessive moisture loss in the exhaust gas. Since absorption is an exothermic process, low temperatures are favoured, whereas higher temperatures also result in loss of adsorbent through evaporation and degradation.

Flue Gas Blower: Flue gas enters the bottom of the absorption tower and flows upward, counter current to the adsorbent flow. Therefore, flue gasses must overcome the pressure drop through the length of the absorber tower. Thus, the cooled flue gas must be pressurized with a blower before entering the absorber.

Absorber: This is a vessel in which the flue gases come into contact with the MEA-based adsorbent that dissolves the CO2 in the flue gases. Columns can be plate-shaped or packed. Most carbon dioxide absorbers are packed columns that use polymer packing to provide a large interfacial area.

Rich/Lean Cross Heat Exchanger: The CO2 loaded adsorbent must be heated to remove the CO2 and regenerate the adsorbent. On the other hand, the regenerated (lean) adsorbent leaving the regenerator must be cooled before it can be recycled back to the absorption column. Therefore, the two sorbent streams pass through a cross heat exchanger where the rich (CO2 loaded) adsorbent is heated and the lean (regenerated) adsorbent is cooled.

Regenerator: In this column, the weak intermediate (carbamate) formed between the MEA-based adsorbent and dissolved CO2 is thermally decomposed. The CO2 is separated from the adsorbent, leaving a reusable adsorbent. For unhindered amines such as MEA, the carbamate formed is stable and requires considerable energy to dissociate. It also includes a flash separator in which the carbon dioxide is separated from most of the water and evaporated adsorbent, producing a fairly concentrated carbon dioxide stream.

Reboiler: The regenerator is connected to the reboiler and is basically a heat exchanger where low-pressure steam taken from the power plant is used to heat loaded adsorbent.

Steam Extractor: In power plants that produce electricity in a steam turbine, a part of LP (low pressure)/IP (intermediate pressure) steam has to be transfer to the reboiler for adsorbent regeneration. Installing a steam extractor is needed to release steam out from the steam turbine.

MEA Recycler: The presence of acidic gas impurities (SO2, SO3, NO2 and HCl) in the flue gas results in the formation of thermostable salts in the adsorbent stream that cannot be dissociated even when heated. To avoid the accumulation of these salts in the adsorbent stream and to recover some of the lost MEA adsorbent, a portion of the adsorbent stream is periodically distilled in this vessel. Adding a strong base, such as caustic, can help release some of the MEA. The recovered MEA is returned to the sorbent stream, while the bottom sludge (recycler waste) is sent for appropriate disposal.

Adsorbent Handling Area: The regenerated adsorbent must be further cooled using a cooler even after passing through the rich/lean cross heat exchanger. This returns the adsorbent temperature to an acceptable level (approximately 40 °C). To compensate for adsorbent losses, a small amount of fresh MEA adsorbent must be added to the adsorbent stream. Therefore, the adsorbent treatment area mainly consists of adsorbent cooler, MEA storage tank and mixer. It also contains an activated carbon bed filter that adsorbs contaminants (degradation products of MEA) from the adsorbent stream.

Carbon Dioxide Drying and Compression Systems: Carbon dioxide products may need to be transported through pipelines over long distances. Therefore, it is best to be free of moisture to avoid pipe corrosion. Of course, CO2 product specifications may vary depending on the end use (or storage/disposal method) and the pipeline's materials of construction. It also needs to be compressed to very high pressures, as it liquefies and can overcome pressure losses during pipeline transportation. A multi-stage compression unit with intercooling and drying provides a final CO2 product at a specified pressure (approximately 2000 psig) with acceptable levels of moisture and other contaminants such as N2.

4.1.3 Modelling

The NGCC Power Plant emerges as a prominent case study in the pursuit of sustainable energy generation to mitigate greenhouse gas emissions in the polish context. This project focuses on modelling the NGCC Power Plant using IPSEpro software to evaluate its performance, particularly with the integration of a carbon capture facility. This initiative aims to evaluate the plant's operational parameters, including gross electrical power generation, efficiency metrics, and energy consumption, while considering real data from the power plant, as well as the simulated results to provide insights regarding the potential advantages and challenges of transitioning to a carbon-neutral namely low-carbon power generation mode.

Table 4.2 presents a comprehensive summary of the operational parameters of the case study NGCC Power Plant operating at nominal load of 100% with production of steam 110 t/h of heat flow without CO2 capture. This table encompasses critical metrics that characterize the plant's performance, such as the efficiency, and energy utilization. The real data collected from the power plant serves as the foundation for analysis, while measured and simulated data provide insights into the potential outcomes of implementing CCS technology. The operational parameters include the gross electrical power from both the gas and steam turbines, as well as their generation efficiency, the gross power plant efficiency, fuel consumption, steam turbine heat rate and gas mass flow rate to the system. These parameters are assessed both in the existing setup and in the simulated scenario with integrated CCS. The modelling is focused on the impact of CCS integration on the plant's operational parameters, particularly focusing on changes in efficiency, energy consumption, and power generation and assess the feasibility of CCS integration in terms of economic viability and environmental benefits. The following sections of this study will deepen the analysis and findings, shedding light on the potential benefits and considerations of adopting CCS technology at the NGCC Power Plant.

Table 4. 2. Summary of operating parameters of CHP NGCC (without CO2 capture, nominal load, operation with steam turbine).

Parameter	Data from the installation	Simulation Data
Gross gas turbine electrical power, MWe	300,0	301,12
Gross steam turbine electrical power, MWe	146,36	133,55
Total gross electric power, MWe	446,36	434,67
Gross power plant efficiency (referenced to LHV), %.	55,18	54,58
Gas turbine gross power generation efficiency referenced to LHV (LHV combustion turbine efficiency), %	38,96	37,79
Gross power generation efficiency of a steam turbine (steam turbine cycle efficiency), %	-	31,04
Gas mass flow rate, kg/s	15,89	15,89

NGCC power plants are an essential component of the modern energy landscape, offering a highly efficient and environmentally friendly means of electricity generation. The efficiency of these power plants is significantly influenced by how steam is utilized in the process. Specifically, when comparing NGCC power plants with and without steam venting, it becomes evident that the way steam is managed has a profound impact on both electric power generation and overall plant efficiency. The critical role steam management plays in NGCC plants and how it can significantly improve their performance as this maximizes the utilization of thermal energy, making the entire process highly efficient and higher efficiency also means fewer greenhouse gas emissions per unit of electricity generated. This is not only economically advantageous but also contributes to a cleaner and more sustainable energy production process, aligning with global efforts to reduce carbon emissions.

4.1.4 Power and Efficiency

The modelled gas and steam turbines collectively generate a total gross electric power of 446.36 MWe, with a steam flow rate of 110 tons per hour. The process involves varying the proportion of exhaust gas recovery from the plant, ranging from 5% to 100%. The capture process occurs at the MEA unit, maintained at 40 °C and 1.20 bar. Both Table 4.3 and Figure 4.4 explain the impact on electricity generation, considering the scenario with CCS.

As the exhaust gas recovery rate increases, the gross power begins to decrease. On average, it drops by 4.27 MW of the electric power allocated for CCS requirements and the NGCC power plant's own needs, resulting in a 1.07% reduction in energy production. This trend becomes more pronounced with higher exhaust gas recovery rates. For instance, at a 50% recovery rate, CCS requires 17.28 MW of power, causing a 3.96% decrease in gross power, equivalent to 392.87 MW compared to the starting value. Beyond 80% recovery, there's a notable shift in energy consumption for CCS. The average reduction in energy consumption between 5% and 80% recovery is approximately 4.3 MW for CCS. However, from 80% to 100% recovery, this decreases to 1.63 MW or 0.44% reduction in power generation.

Table 4. 3. Electrical Power Requirements for CCS Installation (MW)

Share of exhaust gas recovery	NGCC Own Needs (MW)	Exhaust gas compression to 1.2 bar (MW)	CO2 compression (MW)	Total Electric power for CCS purposes (MW)	Net electrical power with CCS (MW)
5%	2.82	0.86	0.59	4.27	431.35
10%	2.82	1.72	1.17	5.71	427.04
15%	2.82	2.57	1.76	7.16	422.74
20%	2.82	3.43	2.35	8.60	418.45
25%	2.82	4.29	2.94	10.05	414.17
30%	2.82	5.15	3.52	11.49	409.90
35%	2.82	6.01	4.11	12.94	405.64
40%	2.82	6.87	4.70	14.38	401.37
45%	2.82	7.72	5.28	15.83	397.12
50%	2.82	8.58	5.87	17.28	392.87
55%	2.82	9.44	6.46	18.72	388.62
60%	2.82	10.30	7.05	20.17	384.37
65%	2.82	11.16	7.63	21.61	380.12
70%	2.82	12.02	8.22	23.06	375.88
75%	2.82	12.87	8.81	24.50	371.63
80%	2.82	13.73	9.40	25.95	370.00
85%	2.82	14.59	9.98	27.39	368.36
90%	2.82	15.45	10.57	28.84	366.73
95%	2.82	16.31	11.16	30.28	365.11
100%	2.82	17.16	11.74	31.73	363.47

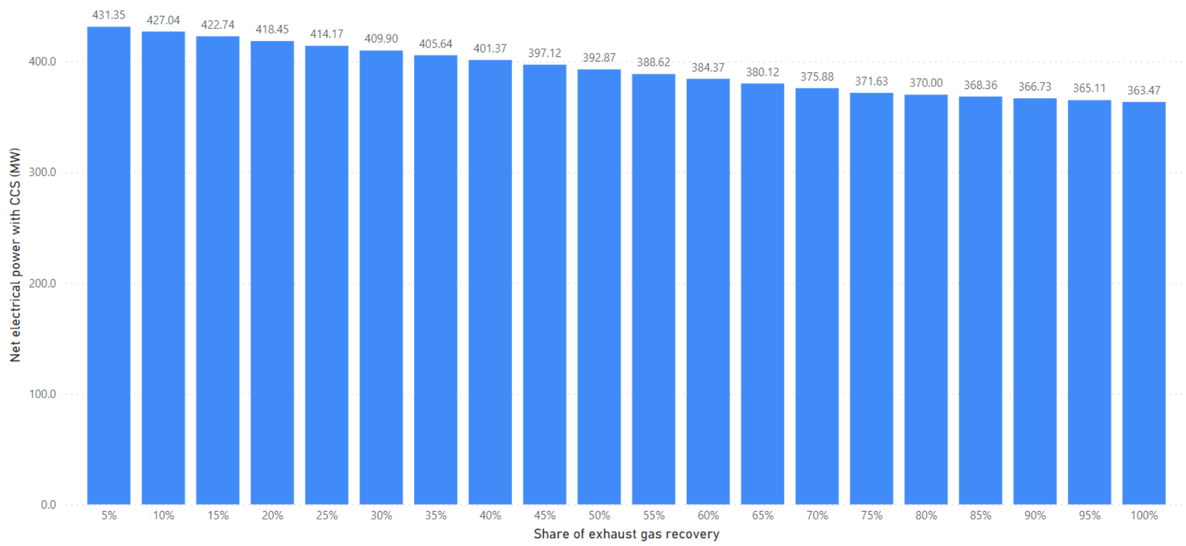

Figure 4. 4. Net power with CCS (MW)

In general, the total net power with CCS (MW) peaks at 100% exhaust gas recovery, resulting in a decrease of 31.73 MW, with 28.91 MW used by CCS equipment. This represents 6.63% of the total power produced by the NGCC power plant. To put it in perspective, against the initial simulated total gross electrical output of 434.67 MW, achieving 100% CO2 recovery from the exhaust gas results in a net output of 363.47 MW, which includes all CCS requirements and auxiliary equipment. This net output dedicated to CO2 capture and own auxiliary equipment accounts for 7.3% of the NGCC power plant's total power production.

In the simulation, it was assumed that the electric power required for CCS operations is derived exclusively from the steam turbine. Figure 4.5, presented on a logarithmic scale, illustrates that the power generation from the gas turbine remains constant at 301.12 MW. Meanwhile, all the energy needed to fulfil the plant's energy-related demands is sourced from the steam turbine.

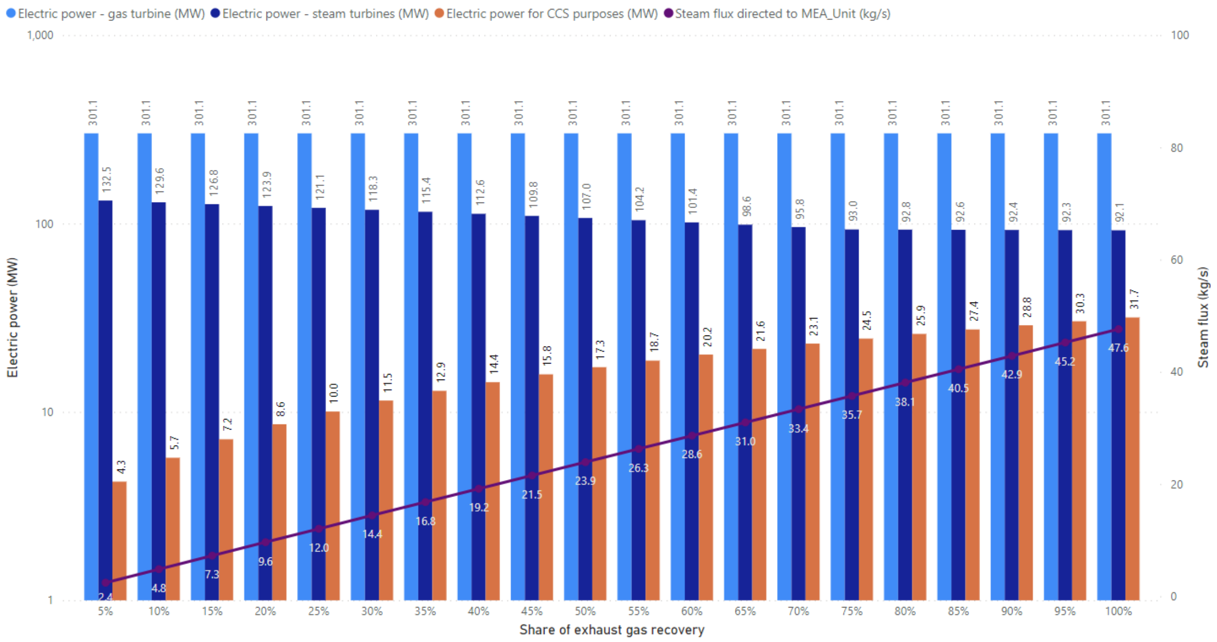

Figure 4. 5. Power and steam used for CCS purposes

This is particularly notable when considering 100% exhaust gas recovery, where the steam turbine's total energy consumption reaches 31.73 MW. To put this in perspective, when compared to the initial conditions, where the gross electrical power of the steam turbine was 133.5 MWe, as indicated in Table 4.2, this energy demand represents 23.4% of the total electrical power. This is equivalent to a steam flow rate of 48 kg/s, which is utilized at the MEA unit for CCS operations.

The primary challenges associated with proposing CCS as an alternative solution within low-carbon power systems are intricately linked to the energy-intensive nature of CO2 capture. This aspect is particularly evident in the context of the NGCC power plant, as depicted in Figure 4.6. To better illustrate this, a range of sensitivity analyses were conducted to understand how varying CO2 capture rates, ranging from 5% to 100%, correspond to different energy demands throughout the process.

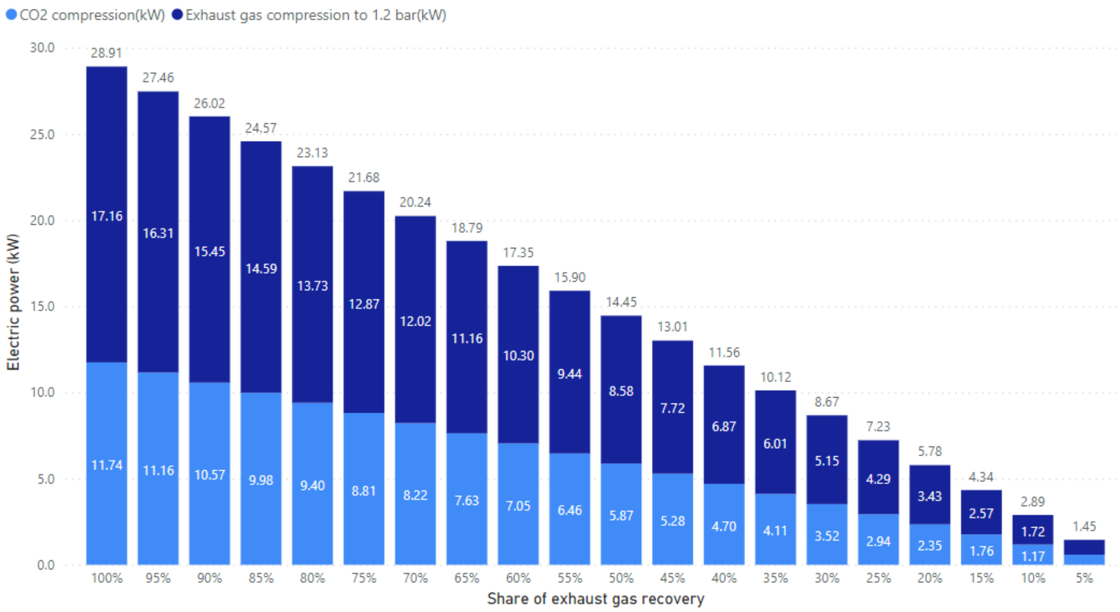

Figure 4. 6. Electric power consumption for exhaust gas and CO2 compression (kW).

Within the carbon capture process, the most energy-consuming operations are related to the treatment of flue gas before it enters the MEA (Monoethanolamine) unit. This requires specific pressure and temperature conditions: 40 °C and 1.20 bar. To achieve this, thermal and electrical energy is used. Thermal energy drives the flue gas compressor, which raises exhaust gases from 1.01 bar, while heat exchangers lower the temperature from 80°C, immediately after exiting the HRSG. Additionally, a significant energy requirement comes from the stripper re-boiler, a key element for removing CO2 from the rich amine solvent.

Furthermore, the CO2 compression equipment of the NGCC power plant system places a significant demand on energy. The configuration comprises a 7-stage compression process utilizing Triethylene Glycol (TEG). The outcome of this process is a stream of compressed CO2, characterized by a temperature of 30 °C and a pressure of 100 bar. Figure 4.6 provides a visual representation of the energy requirements from the steam flow. It shows the energy requirements for both exhaust gas compression and subsequent CO2 compression as a function of different CO2 recovery percentages. At the lower end, with a 5% CO2 recovery rate, the requirement is relatively moderate at 1,445 kW. However, as the CO2 recovery percentage approaches 100%, the power requirement increases significantly, reaching a peak of 28908 kW.

When examining the power plant data presented in Table 4.2 related to the gross power plant efficiency (measured relative to the Lower Heating Value, LHV) in the NGCC power plant simulation stands at 54.58% when operating without CCS. However, when we introduce CCS into the equation, this efficiency metric undergoes notable changes, as depicted in Figure 4.7. Initially, at a 5% exhaust gas recovery rate, the net efficiency is measured at 55.05%, which represents a decrease of 0.43% compared to the efficiency when no gas recovery is in place. The rate at which the efficiency goes down keep steady at an average of 0.54% every 5% steps of capture rate from 5% until 75%. Remarkably, as the CO2 recovery rate is increased to 80%, there is a change in this trend. The average values decreased from 0.54% to 0.21% per 5% of capture share. Then, as the CO2 capture rate reaches 100%, the final efficiency figure is 46.39%. This signifies an overall decrease of 9.09% in efficiency when CCS is implemented in the NGCC power plant.

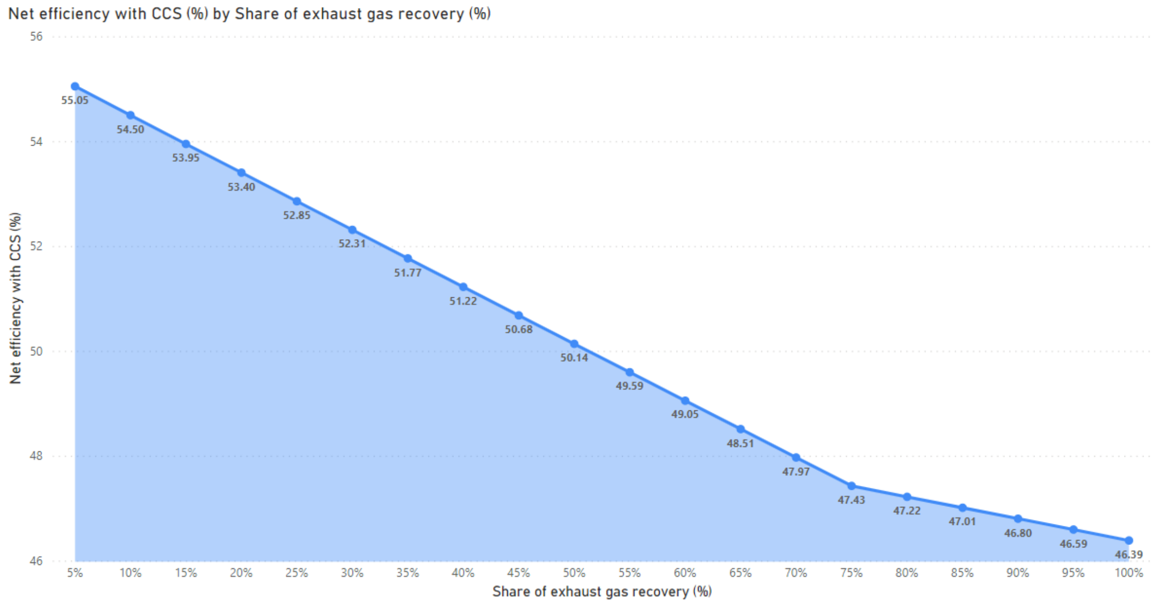

Figure 4. 7. Net efficiency of the NGCC Power Plant with CCS

It is worth mentioning that when referring to "Net efficiency with CCS", it includes the energy required for exhaust gas compression at 1.2 bar and the energy consumption for CO2 compression, including also energy flows (e.g., thermal energy requirement for sorbent regeneration, electrical energy required for mechanical devices such as pumps, fans, compressors, heat exchangers) in the NGCC power plant.

Taking a closer look at the efficiency of each turbine, Table 4.4 and Figure 4.8 clearly indicate that the primary decrease in performance occurs at the steam turbine. To be specific, while the combustion turbine consistently maintains an efficiency of 37.80% relative to the LHV, the efficiency of the steam turbine undergoes a decline from 41.6% at a 5% CO2 absorption rate to 37.92% at a 100% rate. This decrease in the steam turbine efficiency is primarily due to its increased energy demands for CCS purposes, as it predominantly provides the power for these requirements.

Table 4. 4. Gas and Steam turbine efficiencies.

Share of exhaust gas recovery (%)	Gas turbine efficiency (%)	Steam turbine efficiency (%)
5%	37.79	41.60
10%	37.79	41.46
15%	37.79	41.32
20%	37.79	41.17
25%	37.79	41.02
30%	37.79	40.86
35%	37.79	40.70
40%	37.79	40.53
45%	37.79	40.35
50%	37.79	40.17
55%	37.79	39.98
60%	37.79	39.77
65%	37.79	39.56
70%	37.79	39.34
75%	37.79	39.11
80%	37.79	38.86
85%	37.79	38.62
90%	37.79	38.39
95%	37.79	38.15
100%	37.79	37.92

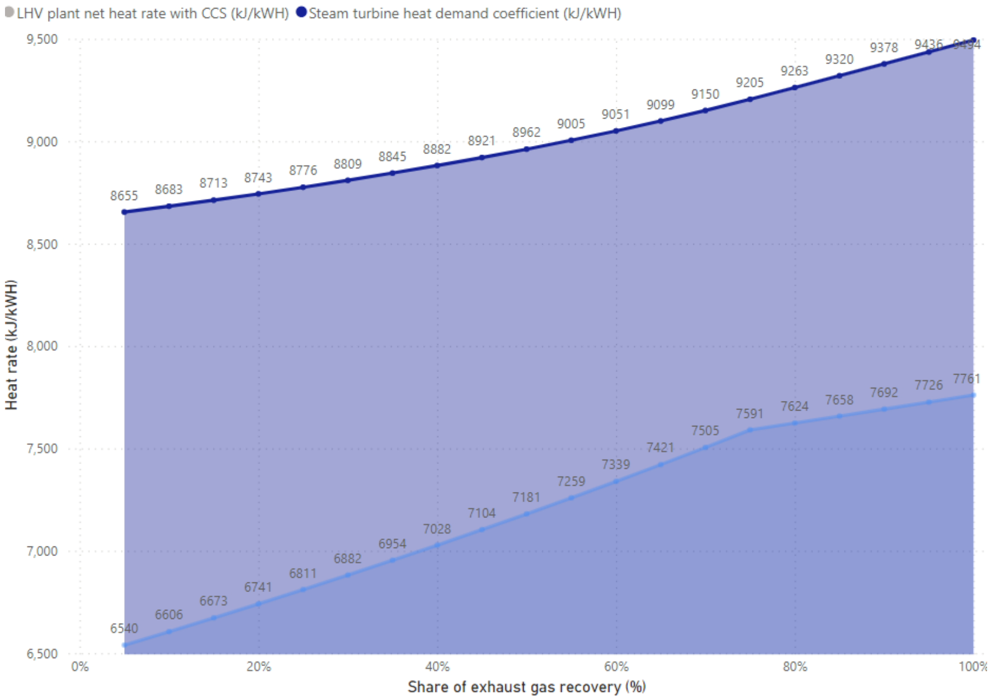

Figure 4. 8. Heat demand for CCS requirement

Analyzing the gas turbine's LHV plant net heat rate, which takes into account all auxiliary equipment, flue gas compression, amine scrubber and CO2 compression, the net heat rate shows variations. Starting at a 5% CO2 recovery rate, the heat rate measures 6540 kJ/kWh, which is 51 kJ/kWh higher compared to 6489 kJ/kWh without CO2 capture.

The heat rate requirements begin to increase sharply, but as seen previously, this trend changes upon reaching an 80% CO2 recovery rate. This transition is evident in Figure 4.8, where the heat rate tends to level off compared to the earlier increments. Finally, when the CO_2 recovery rate reaches 100% the heat rate demand peaks at 7761 kJ/kWh. These heat rates encompass two main components: Firstly, there is an internal consumption of 671 kJ/kWh by the NGCC itself. Secondly, an additional 550 kJ/kWh is required to meet the demands of CCS. These two factors combine to result in a total heat rate of 1221 kJ/kWh from the gas turbine.

As for the steam turbine heat demand coefficient, a steady pattern is observed. Starting at 8655 kJ/kWh with a CO_2 removal rate of 5%, the coefficient maintains its stability and concludes at 9494 kJ/kWh when the CO_2 removal rate is 100%. The total increment in its heat demand coefficient is 840 kJ/kWh. Table 4.4 further demonstrates that as the CO_2 capture rate increases, the heat demand for the gas turbine experiences gradual growth, until it reaches 80%. Beyond this point, the trend levels off, indicating that the heat demand remains relatively stable after achieving an 80% capture rate.

4.1.5 Results: CO2 emissions

The replacement of coal-fired units with natural gas combined-cycle units contributes to a decline in emissions, which generates approximately 40% of the GHG emissions per megawatt-hours (MWh) of power output compared to conventional coal-fired units. This improvement is due to the fact that natural gas units exhibit an average emission rate of 898 pounds of CO_2 per MWh, whereas coal units emit at a significantly higher rate of 2.180 pounds of CO_2 per MWh[75]. Table 4.5 summarizes emission factors of flue gasses and solid pollutants within the context of the NGCC case study power plant in Poland modelled using IPSEpro. Notably, CO_2 constitutes 4.13% vol. of the total exhaust gases, with the remaining components including N_2 at 74.28% vol., O_2 at 11,76% vol., and H_2O at 8,95% vol.

Table 4. 5. Summary of emission factors for CHP NGCC (without CO2 capture, no steam vent).

Parameter	Data from the installation	Simulation Data
CO emissions, ppm	-	-
NOx emissions, ppm	-	-
SO2 emissions, ppm	-	-
Dust, mg/m3	-	-
CO2 in fuel, % vol.	-	0,2286
CO2, % vol.	4,13	4,14
Ar, % vol.	0,88	-
H2O, % vol.	8,95	8,16
N2, % vol.	74,28	77,81
O2, % vol.	11,76	9,89
SO2, ppmv	1,145	-

The total modelled exhaust gas stream remains constant at 671.03 kg/s throughout the operation of the NGCC power plant. In Figure 4.9, the flue gas stream diverted from the chimney and directed to the MEA (Monoethanolamine) unit at various flow rates is represented as a light blue shadow. This process starts with a flow rate of 33.55 kg/s at 5% operation, during which 1.9 kg/s of CO2 is absorbed by the amine sorbent. The remaining exhaust stream, equal to 637.48 kg/s, is emitted into the atmosphere. These proportions begin to change as the flow rate percentage of the flue gasses increases through the MEA unit. At 100% of the flue gas flow through the MEA unit, the process yields a pure CO2 stream of 38.97 kg/s out of the 671.03 kg/s of exhaust gases. This CO2 capture process requires a steam flow of 47.61 kg/s. It is important to highlight that when there are high CO2 flows, a substantial portion of the steam flow is redirected to the MEA Unit rather than being utilized in the steam turbine, where it could otherwise contribute to electricity generation.

The CO2 concentration in the process is depicted in Figure 4.9 as a dark blue shading and represents the CO2 stream captured after passing through the MEA Unit. The percentage of CO2 withing the exhaust gas stream is equivalent to 5.81% and stay the same from 5% until 100% over the total flue gas amount and is pictured as a white shadow in the graph.

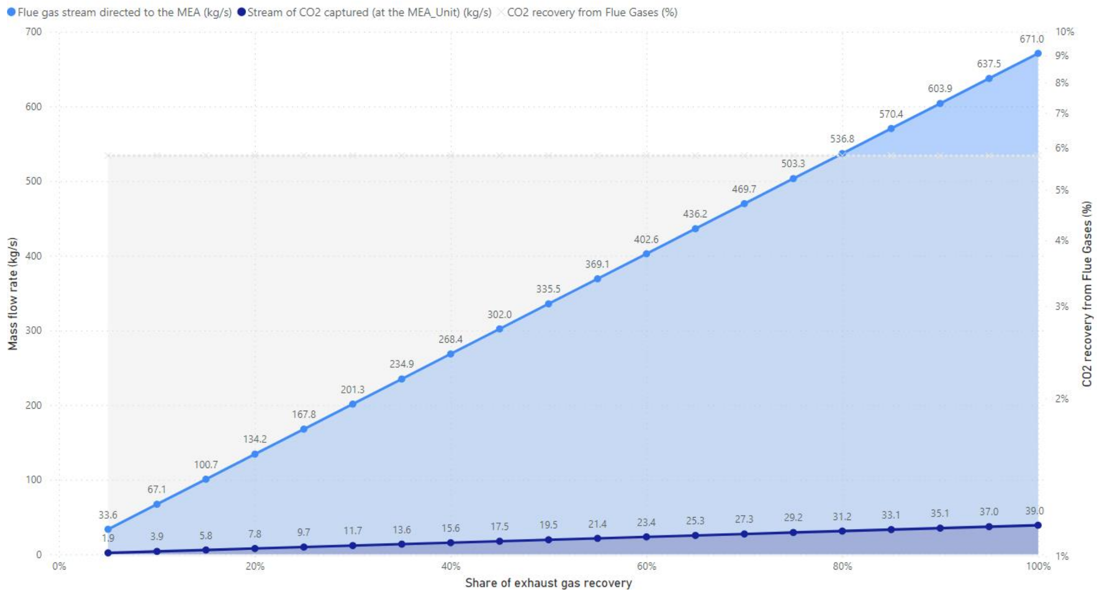

Figure 4. 9. Stream of CO2 captured after exit from MEA Unit (kg/s)

In Table 4.6 and Figure 4.10, it's clear that changes in the CO2 recovery rate during the capture process led to the release of the remaining portion of the CO2 stream into the atmosphere. The cumulative CO2 emissions for the NGCC power plant scenario were calculated using IPSEpro and yielded a value of 38.97 kg/s when a 100% capture rate was implemented, as shown previously in Figure 4.9. This value translates to an annual potential CO2 reduction of 1,228,945.228 tons if the amine-based CCS technology, examined in this project, were to be retrofitted at the NGCC power plant case scenario. The adjustment in the capture rate was made to highlight the impact of CCS on the decarbonization of power systems, even at lower capture rates.

Table 4. 6. CO2 Emissions with and without CCS

Share of exhaust gas recovery	CO2 emitted per year (ton/year)	CO2 abated per year (ton/year)
5%	1,167,497.87	61,447.36
10%	1,106,050.62	122,894.61
15%	1,044,603.44	184,341.78
20%	983,156.80	245,788.43
25%	921,708.90	307,236.33
30%	860,261.66	368,683.57
35%	798,814.40	430,130.83
40%	737,367.14	491,578.09
45%	675,919.88	553,025.35
50%	614,472.61	614,472.61
55%	553,025.35	675,919.88
60%	491,578.09	737,367.14
65%	430,130.83	798,814.40
70%	368,683.57	860,261.66
75%	307,236.31	921,708.92
80%	245,789.05	983,156.18
85%	184,341.78	1,044,603.44
90%	122,894.52	1,106,050.70
95%	61,447.26	1,167,497.97
100%	0.00	1,228,945.23

In Figure 4.10 capture rate starts at a conservative 5%, effectively capturing 61.447,36 tons of CO2 per year. The importance of this capture becomes more evident when the rate reaches 40%, which translates into an annual abatement of approximately 500 kilotons of CO2. However, the true impact takes place at an 80% capture rate, where a substantial reduction of nearly 1 million tonnes of CO2 per year is achieved. This reduction represents a significant contribution to mitigating climate change, particularly within the Polish context, marking an important milestone in carbon abatement within the power sector.

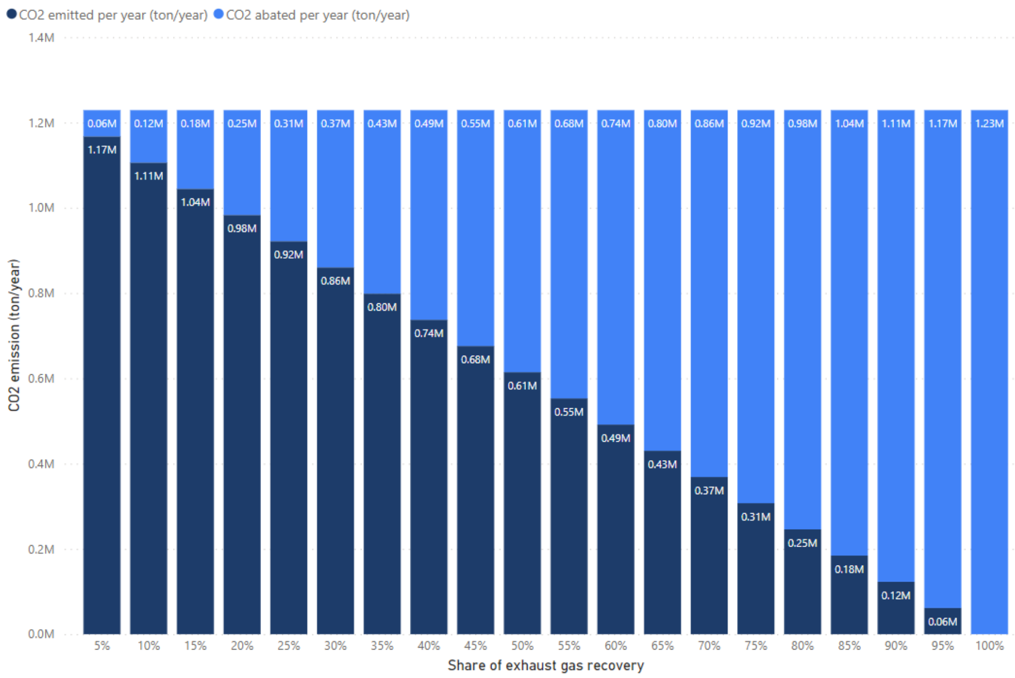

Figure 4. 10. CO2 emitted per year and CO2 abated per year (ton/year)

In this thesis, it was examined the economic implications of reducing CO_2 emissions within the Polish power sector. To assess this impact, we relied on the current carbon tax rate in Poland, which has consistently remained one of the lowest in Europe at €0.07 per ton of CO_2 since 1990, as reported by the World Bank dataset [76]parison, it was also considered carbon tax rates from other European countries. Notably, it was examined Norway, one of the most committed countries to achieving Net-Zero emissions in the EU, with a carbon tax rate of €84.76 per ton of CO_2. Additionally, Portugal, known for its greener energy matrix, was included, with a carbon tax rate of €24 per ton of CO_2. It was also referenced the EU ETS with a rate of €89 per ton of CO_2. Furthermore, it was factored in the average carbon tax rate in Europe, which stood at €42.77 per ton of CO_2 for the purposes of our analysis. This consideration is based on the expectation that Poland's carbon tax may eventually align with the rates observed in other EU member countries, which could significantly impact the economics of emissions reduction in the Polish power sector.

Figure 4.11 provides a visual representation of the economic impact due to CO_2 emissions of a 435 MW NGCC power plant in Poland, when compared to its potential performance in different countries or under varying carbon pricing scenarios. The figure clearly illustrates that, given the current carbon tax rate in Poland, the implementation of CCS may not be economically sustainable. The cost associated with emitting 1,228,945.228 tons of CO_2 annually, as computed using IPSEpro, amounts to only €86,026.17 when subject to a tax rate of €0.07 per ton of CO_2.

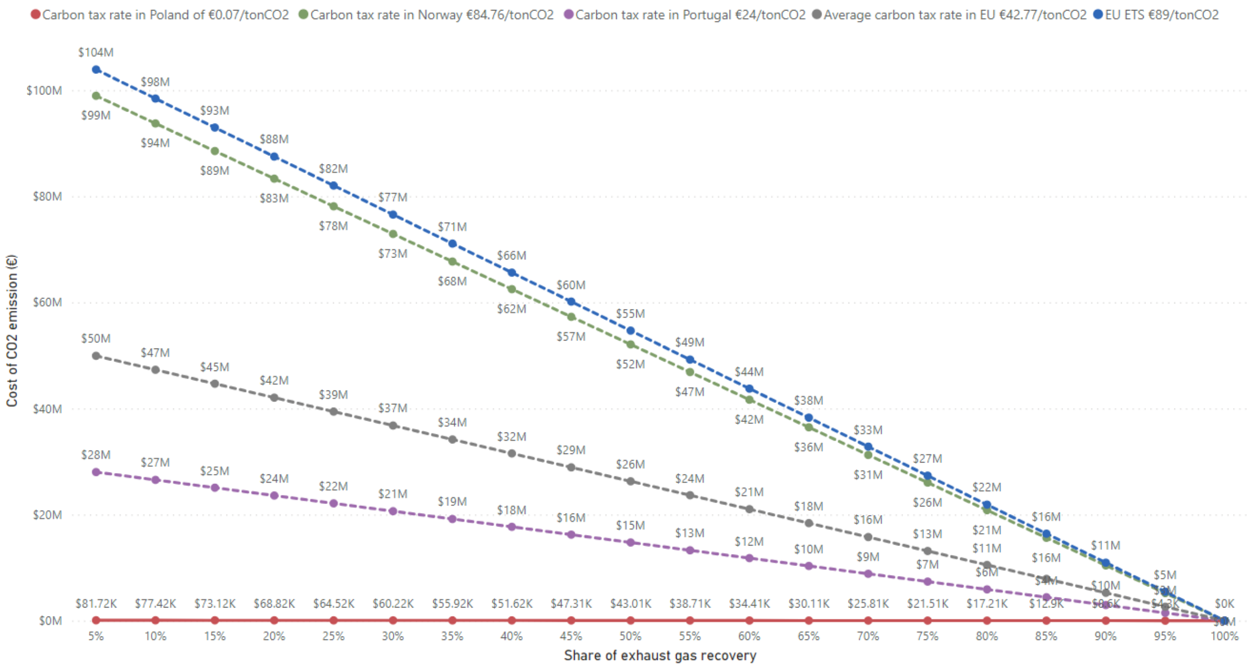

Figure 4. 11. Cost of CO_2 emissions in Poland compared to other European countries

In contrast, this cost increases significantly to €29,494,685.46 if the same NGCC plant were situated in Portugal, or €52,561,987.387 when subject to the EU average carbon tax rate. Furthermore, this cost escalates sharply when compared to the carbon tax rate in Norway, reaching €104,165,397.50, or under the EU ETS at €109,376,125.26.

4.2 Case Scenario for CO2 Storage

In section 3.1.3, it was pointed out that Poland has considerable storage potential, as indicated by the assessment conducted in the framework of the EU GeoCapacity project, particularly in saline aquifers at approximately 14,495 Mt, estimated and distributed over several structures/sites (I, II, III, IV, V, VI, VII, VIII), as shown in Figure 3.5, but still remains largely uncharacterized. As mentioned before, the legislation restricts usable storage sites to zone VIII, which covers only the Łeba-Baltic Sea region, including offshore areas. This limitation mainly concerns the CO2 emission potential of the northern parts of the country[40].

The optimal conditions for underground CO2 storage in Poland are identified within the expansive Mid-Polish Mesozoic Basin (Polish Lowlands), specifically in Northern and Central Poland. Here, sedimentary rocks of diverse ages, primarily Mesozoic and Cenozoic, offer well-defined geological features. These rocks exhibit good reservoir properties, characterized by large thickness, extent and porosity, with fewer fractures or fissures. Moreover, the impermeable rocks at the top provide an effective seal for the storage sites[77]. An in-depth analysis of deep aquifers in the Polish Lowlands performed by The Institute of Mineral Resources and Energy Management of the Polish Academy of Sciences (IGSMiE PAN) underscores the existence of several key factors favoring underground CO2 storage, such as thick reservoir rocks, a lack of contact with potable water aquifers, position at depths beyond 1000 m, a good geological characterization, and an overburden that supports secure storage conditions. Notably, the analysis highlights three Mesozoic aquifers—the Lower Triassic, Lower Jurassic, and Lower Cretaceous—as the most suitable sites for exploring reservoirs and identifying geological structures for underground carbon dioxide storage, the properties of these are shown in Table 4.7.

Table 4. 7. CO2 storage capacity in the Lower Cretaceous, Lower Jurassic and Lower Triassic aquifers

Formation	Area (km2)	Porosity (%)	Net gross ratio (%)	ρCO2 (kg/m3)	Storage capacity (Mt)
Lower Cretaceous	24,562.00	20.5	40	800	7,646.90
Lower Jurassic	70,106.00	17.3	60	700	43,825.70
Lower Triassic	112,036.00	9.7	70	600	26,494.10

Credit: EU GeoCapacity Project results[77]

The largest CO_2 storage volume is found in the Lower Jurassic formations, followed by the Lower Triassic and the smallest in the Lower Cretaceous. The total storage is 77,966.7 Mt and covers Poland's emissions for 195 years, with the emissions level of 400 Mt reported in 2021.

In Zone VIII, the primary aquifer is the Cambrian, extending across both offshore and onshore areas. The Cambrian reservoir represents the base of the Baltic Basin sedimentary infill. The reservoir consists of quartz sandstones with underlying siltstones and shales. In terms of hydrocarbon fields suitable for CO_2 storage, the only offshore oil field currently identified for this purpose is the depleted B3 field (74.12% recovered reserves) of the middle Cambrian, located about 70 km north of the northernmost part of the Polish coast within the exclusive economic zone in the Baltic Sea and operated by LOTOS Petrobaltic. The estimated storage capacity of the B3 field is 7.0 Mt. [77]. Regarding offshore saline aquifers, Table 4.8 outlines the parameters for two structures situated in sector VIII within the Middle Cambrian formation with larger storage capacity. Therefore, CO_2 storage within saline aquifers is the optimal choice in the Baltic Basin, given its large capacity compared to hydrocarbon fields.

Table 4. 8. Parameters for the saline aquifer structures in Zone VIII

Name	Area (km2)	Reservoir thickness (m)	Depth (m)	Average permeability (mD)	Average porosity (%)	Salinity (g/l)	Temperature (°C)	Reservoir pressure (Mpa)	Storage efficiency (%)	Storage capacity (Mt)
Block N(B)	2200	70	2200	50	10	30	60	20	2	861,3
Block E	1000	100	2060	200	15	30	55	20	1	776,0

Credit: Polish Geological Institute - National Research Institute (PGI-NRI) [54]

Hence, the Sleipner project stands out as one of the most compelling examples of CCS technology. It has proven the feasibility and safety of geological storage of CO_2 in saline aquifers. It therefore serves as a key reference for the implementation of CCS in Poland in the offshore Baltic Sea area and plays a crucial role in the country's efforts to reduce CO_2 emissions from industrial and energy operations.

In Sleipner the CCS facility was adapted to remove CO_2 from natural gas, which contains a CO_2 concentration of around 9-10% and has to be reduced to less than 2.5 % for the gas to meet saleable specification, so the CO_2 is separated at the Sleipner T platform via amine scrubbers. Once captured, the CO_2 is injected in the Utsira formation, which is a relatively shallow saline aquifer located 800 m beneath the seabed, a diagram of the Sleipner scheme is given in Figure 4.12[51]. Approximately 1 $MtCO_2$ is injected underground annually via a single deviated well, sub-horizontal at the injection point which is located 1012 m below sea-level, some 200 m below the Utsira formation top. The CO_2 injection operation started in October 1996 and by 2016 around 16 $MtCO_2$ had been stored at a rate of approximately 2700 t day in the Utsira sandstone formation[51, 78].

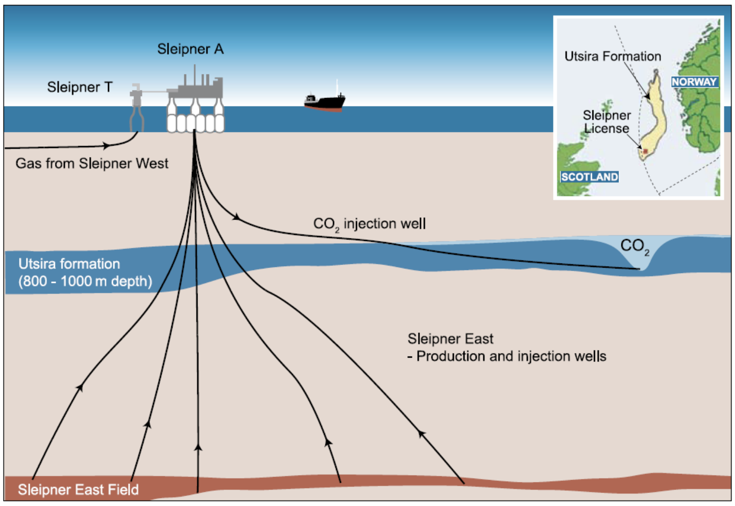

Figure 4. 12. Simplified diagram of the Sleipner CO2 Storage Project.

Credit: IPCC Special Report on Carbon Dioxide Capture and Storage [51].

In this study, the assessment covers the examination of two offshore saline aquifers, Block N(B) and Block E, against Sleipner characteristics, using IECM. Within the framework of this thesis, the objective is to provide valuable information to close the loop of the 1 million tonnes of CO2 emissions from the NGCC power plant obtained above 80% capture rate, as seen in Section 3. This involves estimating the CO2 storage potential and identifying a suitable storage site to effectively sequester CO2 back to its original source. It is noteworthy that while aquifers in the Mid-Polish Mesozoic Basin, particularly in the Lower Jurassic, have a higher storage capacity than those in the Baltic Basin, their onshore location and existing constraints have excluded them from the modeling process.

4.2.1 IECM

The Integrated Environmental Control Model (IECM) [79] created by Carnegie Mellon University (CMU) for the U.S. Department of Energy, is a comprehensive computational tool designed for the preliminary assessment and analysis of clean fossil-fueled power generation technologies, such as the Natural Gas Combined Cycle (NGCC) system considered in this master thesis. This computational framework facilitates the thorough evaluation of cost and performance metrics associated with various fossil fuel power plants, incorporating different emission control configurations with CCS. Using the IECM, this research work aims to provide a systematic exploration of the operational drivers of power plants integrating CCS technologies, such as the post combustion amine capture method used in this thesis.

The analysis extends to deep saline reservoir storage, providing a mapped understanding of storage capacity using the Law & Bachu correlation for estimating the number of wells required for a given flow rate[80] based on reservoir characteristics. This correlation relates mass injection rate to reservoir permeability, considering factors such as aquifer thickness, absolute permeability, CO2 relative permeability, density, dynamic viscosity, and well radii by using regression analysis and a steady-state radial outflow model, leading to the following relation for CO2 injectivity as a function of its mobility:

$$\frac{Q}{[D \text{ x } (Pi - Pa)]} = 0.000538 \text{ x } \rho \text{ x } (kkr/\mu) \;/\; \ln(re/rw) \ldots\ldots\ldots\ldots (4)$$

Here, the first term represents CO2 injectivity (mass injection rate Q in t/d per aquifer unit-thickness for a unit pressure difference between injection and aquifer pressures Pi and Pa, in MPa, respectively).The term (kkr/μ) represents CO2 mobility, D is aquifer thickness (m), k is absolute permeability (10^{-15} m²), kr is CO2 relative permeability (1 for 100% CO2 injection), ρ and μ are CO2 density (kg/m³) and dynamic viscosity (mPa.s), respectively, and rw and re are the radii of the injection well and injection influence, respectively.

4.2.2 Modelling

For the modeling phase, the analysis relies on comparing Sleipner with two offshore saline aquifers, Block N(B) and Block E, located in the Zone VIII of the Baltic Sea. This case scenario was used considering the limitation that Poland establishes regarding the use of onshore sites, making the Sleipner project a noteworthy offshore CCS pioneer that can serve as a blueprint for the Baltic region. It is compelling to note that the screening of a suitable site for CO2 storage in Poland's maritime areas should adhere to key geological selection criteria. These criteria include reservoir depth, thickness, porosity, permeability, seal integrity, and salinity, as outlined in the best practices guidelines for CO2 storage in saline aquifers from the SACS and CO2STORE projects. Table 4.9 summarizes the main parameters utilized for modeling the storage conditions.

In addition, Sleipner was selected for this scenario because of its verified top seal, a feature also presents in the Block B and E aquifers which are structural traps. It is well-established that the capacity for CO2 storage depends not only on the properties of the reservoir rock itself but also on the nature of its boundaries, which play a significant role in retaining CO2 in the desired storage location[81].

Table 4. 9. Reference Model Input Parameters

Model Parameters	Unit	Block N(B)	Block E	Sleipner - Utsira [82] [83]
Area	(km2)	2200	1000	26100
Reservoir thickness	(m)	70	100	200 - 300
Depth	(m)	2200	2060	800
Average permeability	(mD)	50	200	1100 - 5000
Average porosity	(%)	10	15	27- 42
Temperature	(°C)	60	55	29 – 35.5
Reservoir pressure	(Mpa)	20	20	2 – 5.5

Table 4.9 reveals notable distinctions among the reference model input parameters for Block N(B), Block E, and Sleipner. Sleipner stands out with a considerably larger area (26100 km2) compared to Block N(B) (2200 km2) and Block E (1000 km2). In terms of reservoir characteristics, Sleipner exhibits a broader range of thickness (200 - 300 m) in contrast to the comparatively thinner reservoirs in Block N(B) (70 m) and Block E (100 m). Additionally, Sleipner is situated at a shallower depth (800 m) relative to Block N(B) (2200 m) and Block E (2060 m). Sleipner's reservoir also boasts higher permeability (1100 - 5000 mD) and porosity (27 - 42%) compared to the other locations. Moreover, Sleipner experiences lower temperatures (29 – 35.5°C) and significantly lower reservoir pressure (2 – 5.5 MPa) compared to Block N(B) and Block E. These variations in geological and reservoir parameters are pivotal considerations for evaluating the feasibility of carbon capture and storage initiatives across these regions.

4.2.3 Results: CO2 storage

In this study, a predefined set of values was established using reference data from Sleipner, representing optimal conditions for CO2 storage in offshore saline aquifers. The study focuses on the offshore area of the Baltic Sea relevant to Poland, with specific attention to Block N(B) and Block E. The parameter settings are detailed in Table 4.9 and visually depicted for each scenario in Figures 4.14, 4.15, and 4.16. For all cases, a uniform storage coefficient of 2.6% [84] was defined, as per the technical report conducted by the IEA Greenhouse Gas R&D Program for carbon dioxide storage in deep saline formations. Additionally, the average injection rate was standardized at 1 Mt CO2 per year, aligning with the CO2 recovery share of 85%, as obtained from Table 4.6.

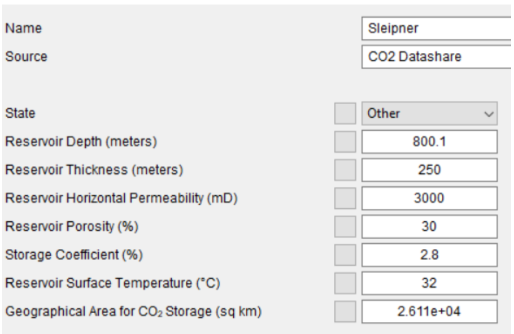

Figure 4. 13. Set parameters for Sleipner offshore saline aquifer.

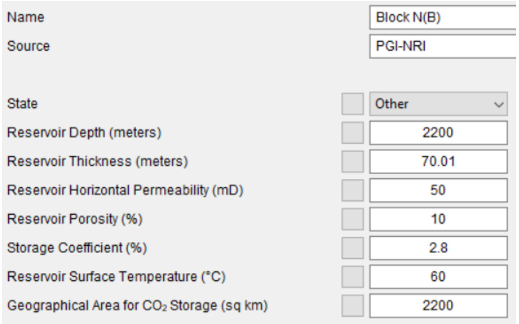

Figure 4. 14. Set parameters for Block N(B) offshore saline aquifer.

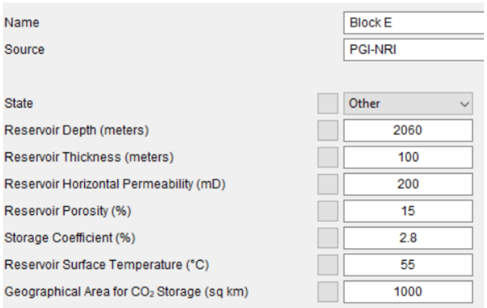

Figure 4. 15. Set parameters for Block E offshore saline aquifer.

Based on the CO2 storage capacity findings derived from the specified properties for Sleipner, Figure 4.17 illustrates that approximately 40,130 Mt of CO2 can be effectively stored in the reservoir. This entails the deployment of a minimum of two CO2 injection wells to accommodate a plume size of 22.51 km². In relation to Block N(B) and Block E, Figures 4.18 and 4.19 depict that, based on the properties used, these offshore aquifers have the potential to store 367 and 360.9 Mt of CO2, requiring 3 and 2 injection wells, respectively. The size of the CO2 plume for Block N(B) is 204.8 km², while for Block E, it is 94.51 km². The plume size for the Baltic Sea aquifers is significantly higher than that for the North Sea one, attributed to the smaller size of the storage area for the Baltics.

This correlation also highlights the importance of determining the most appropriate well configuration in terms of CO2 injectivity. However, as much as a configuration holds significant potential for increasing the injection rate, it also means a greater impact in terms of infrastructure and surface facility costs. A positive factor in Sleipner that does not exist in the Baltic aquifers is the location of the reservoir at a shallower depth of 800 m compared to Block N and Block E at 2200 and 2090 m, which also implies higher drilling and completion costs. Indeed, the use of a saline aquifer provides plenty of storage capacity, which has a substantial impact on mitigating national CO2 emissions, while taking advantage of the CO2 storage resources available in the country.

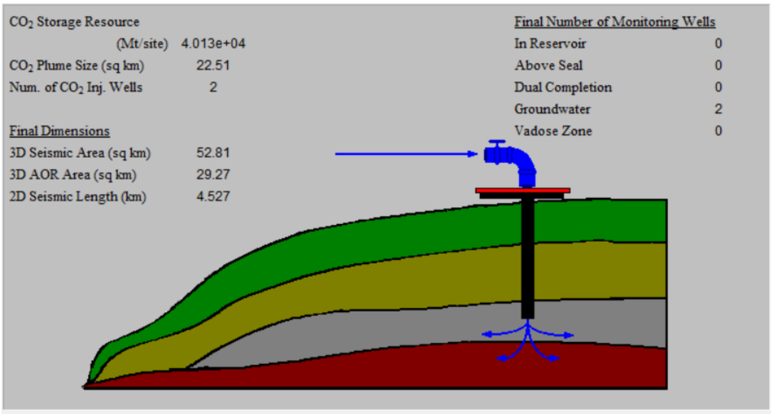

Figure 4. 16. CO2 Storage Diagram for Sleipner.

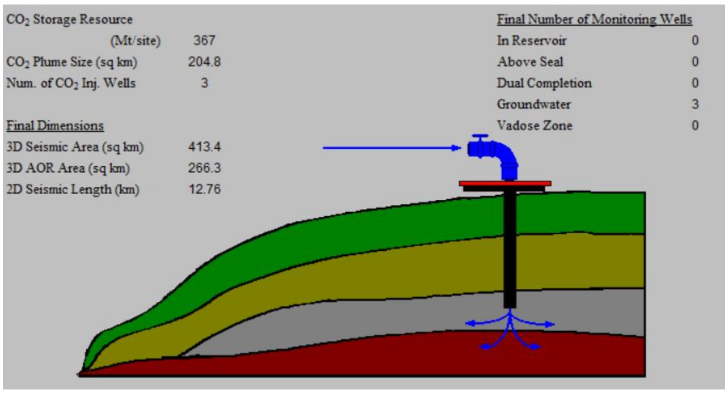

Figure 4. 17. CO2 Storage Diagram for Block N(B).

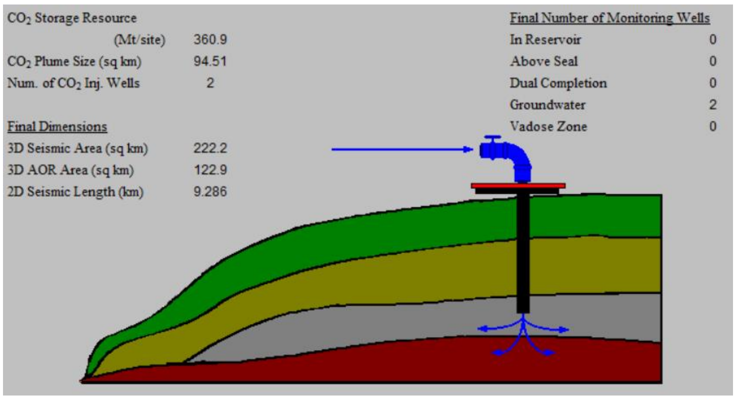

Figure 4. 18. CO2 Storage Diagram for Block E.

Furthermore, when assessing the storage potential of a site, careful consideration is critical due to the inherent uncertainties. The technical and industrial challenges associated with prospecting storage sites require careful consideration, encompassing both the short-term risks and the long-term fate of the stored CO2. To address these complexities, advanced software tools such as Halliburton's Permedia® or TNavigator™ developed by Rock Flow Dynamics have emerged as solutions. These sophisticated software platforms play a crucial role in assessing and mitigating uncertainties, offering enhanced capabilities for comprehensive assessments in the field of carbon capture and storage. These tools can serve as valuable assets for future, more advanced studies beyond the scope of this current research, as they offer a comprehensive approach to pressure and fluid dynamics when simulation CO2 injection.

Chapter 5

5. Conclusions

The study primarily focuses on modeling an NGCC Power Plant in Poland, with a specific emphasis on evaluating the integration of a post-combustion amine-based CCS facility. It's crucial to underline that the NGCC Power Plant plays a pivotal role in Poland's transition to sustainable energy generation and the reduction of greenhouse gas emissions. The study provides detailed operational parameters, including power generation, efficiency, energy consumption, and other critical metrics. Notably, efficient steam management has a significant impact on NGCC power plant efficiency. Proper steam utilization can result in increased efficiency, decreased greenhouse gas emissions, and enhanced sustainability. It's worth noting that in the simulations, there is no substantial difference in the steam turbine heat demand beyond an 80% capture rate. Beyond this point, the heat demand remains relatively stable.

The integration of CCS technology impacts the NGCC Power Plant's operational parameters, particularly in terms of efficiency, energy consumption, and power generation. CCS technology comes with increased energy demands, primarily for the capture and compression of CO2. The energy-intensive nature of CO2 capture presents a notable challenge. As the CO2 recovery rate increases, the net efficiency of the power plant decreases. Specifically, at a 100% CO2 recovery rate, the overall efficiency decreases by 9.09%. This reduction in efficiency is primarily attributed to the energy requirements of CCS operations, underscoring the trade-off between reducing emissions and maintaining energy efficiency. Notably, there is a significant shift in the NGCC Power Plant's performance at an 80% recovery rate, with an overall efficiency decrease of 8.26%. Therefore, it is advisable to set the capture rate for the NGCC at a level higher than 80%, as there is no significant impact on efficiency beyond this threshold.

The recommendations provided in Table 4.9 offer a foundation for the design and operation of CO2 capture and transport preparation facilities for the Case Study Combined Heat and Power Plant. Efficient management of energy demands, optimization of CO2 capture rates, and the exploration of energy recovery options will be pivotal in achieving sustainability and emission reduction targets. Continuous monitoring and evaluation of the chosen systems will be necessary to ensure they perform as expected and to make any necessary adjustments for maximum efficiency and environmental benefit. In addition to the recommendations provided in Table 4.9, it is crucial to consider further analyses and potential modifications aimed at mitigating the energy penalty in the steam turbine and optimizing the overall performance of the NGCC power plant. Here are some specific recommendations: Firstly, an analysis of the combustion chamber temperature control should be undertaken to explore the possibility of modifying it to enhance energy efficiency. Adjusting the combustion temperature can have a profound impact on both power generation and emissions control, potentially leading to improved turbine performance and reduced energy penalties. Secondly, evaluating the efficiency of the air compressor system is essential. Opportunities to enhance the compressor's performance, such as through advanced designs or control strategies, should be explored, as this directly affects the plant's overall efficiency. Thirdly, investigating various combined cycle configurations could help identify layouts that minimize energy penalties, considering different arrangements of gas and steam turbines and the heat recovery steam generator (HRSG). Implementing advanced control systems is another key recommendation, as these systems can dynamically optimize plant operations based on real-time conditions, thereby maintaining optimal efficiency.

Table 4. 10. Recommendations for the selection of CO2 capture and transport preparation facilities for the Case Study Combined Heat and Power Plant

Parameter		**Notes and comments**
CO2 capture method	amine absorption	commercially available technology (TRL 9) With demonstration installations in the power sector worldwide
Capture reference system	Shell Cansolv	in accordance with the best state of the art and applicability for flue gases from the combustion of natural gas
Unit heat demand for amine regeneration	approx. 2.9 GJ/Mg CO2	According to the obtained literature data for the working medium (amine solution) Cansolv
CO2 capture rate	min. 85%	According to the assumptions of the work and the technological feasibility for commercial solutions, including the capture reference plant
Steam intake point for amine regeneration	From the vias between the medium and low-pressure parts of the steam turbine unit	The possibility of recovering some of the steam energy extracted from the steam turbine unit in a dedicated expansion turbine
Number of process lines of CO2 capture plants	1	According to the best state of the art and data for the reference capture system
CO2 compression pressure for transport	approx. 10 MPa	pressure required to transport CO2 up to a distance of about 60 km without the need for a CO2 recompression station on the transport pipeline
Compression reference system	Compression reference system 7-stage compression system with intercooling	according to the best state of the art for commercial solutions; possibility to use waste heat from intercooling of CO2 compressors as part of thermal integration with steam-water circuit and district heating circuit; 2 process lines according to the best state of the art
Reference layout of preparation for transport	TEG moisture separation system	In accordance with the best state of the art for commercial solutions; lowering the moisture content to less than 50 ppmv in accordance with the requirements on the transport and storage side of CO2
Nominal volume of CO2 for transport and storage of CO2	Up to about 1.1 million Mg of CO2 per year	Assuming nominal load for unit availability of 90% and assumed CO2 capture rate at gross rated capacity of 435 MW.

Furthermore, exploring waste heat recovery from different plant processes, integrating Combined Heat and Power (CHP) systems, continuously optimizing carbon capture processes, conducting comprehensive simulations and modeling studies, implementing robust data monitoring and analysis systems, and engaging in collaborative research efforts are all essential strategies to achieve energy efficiency and sustainability goals.

In addition, using modeling tools such as IPSEPro for analysis and decision-making offers several advantages: 1. IPSEPro allows for precise modeling and simulation, ensuring that the recommendations are based on accurate data and system behavior predictions. 2. The tool likely enables a comprehensive evaluation of various parameters and scenarios, leading to well-informed recommendations that consider multiple factors. 3. The use of simulation tools can streamline the analysis process, saving time and resources compared to physical experimentation. 4. The recommendations are data-driven, which enhances their reliability and credibility. 5. IPSEPro likely allows for the testing of different scenarios and configurations, enabling a thorough examination of the NGCC Power Plant's performance under various conditions. It's important to emphasize that utilizing advanced simulation and modeling tools like IPSEPro is a valuable approach for making informed decisions in complex projects like power plant optimization and environmental impact reduction. The recommendations derived from such tools are more likely to result in effective and efficient solutions.

The observation that Poland maintains a relatively low cost for CO2 emissions, with a carbon tax rate of €0.07 per ton of CO2, highlights a crucial aspect of the carbon pricing landscape in the country. This low carbon tax rate suggests that, from an economic standpoint, there may be less immediate financial incentive for industries to invest in emissions reduction technologies like CCS. In comparison to other European countries with higher carbon tax rates, such as Norway, Portugal, and the EU average, Poland's lower carbon pricing might make the adoption of emissions reduction technologies less financially attractive. This economic context underscores the importance of aligning carbon pricing policies with environmental goals, especially in the context of power generation.

For decision-makers in the Polish power sector, finding the right balance between environmental aspirations and economic feasibility is essential. While reducing carbon emissions is a global imperative, it must be done in a way that doesn't overly burden industries and consumers with high costs, which could impact economic competitiveness. The challenges and opportunities associated with transitioning to low-carbon power generation in Poland are complex and require careful consideration. It may be necessary for Poland to review and potentially adjust its carbon tax rates to align with EU standards, ensuring that its industries remain competitive and sustainable within the broader European market. Bringing to life CCS demonstration projects in Poland, such as the one proposed in this thesis, offer a practical testing ground to assess the real-world feasibility and effectiveness of CCS technology. By actively addressing performance issues and identifying and resolving bottlenecks, valuable insights can be gained, leading to refinements that improve the overall cost-effectiveness of CCS. The success of such demonstration projects like this one can serve as a catalyst for broader adoption and investment in CCS technology. As stakeholders witness the tangible benefits and the potential for emissions reduction, they are more likely to embrace CCS as a viable solution to tackle carbon emissions in the power sector.

Regarding storage capacities, the Baltic Sea area in Poland holds promising potential to develop into a significant CCS complex. Such a complex could play a pivotal role in capturing CO2 emissions from industrial facilities and transporting them to offshore storage sites for permanent containment, mirroring successful models like The Northern Lights CCS project in Norway. However, a comprehensive exploration of the potential and conditions for geological storage in the Baltic Sea Region requires a cooperative effort with other nations sharing this area of interest. Establishing a fundamental regional network of CCS is essential, as it has the potential to collaboratively drive the deployment of CCS initiatives. Notably, on the Polish side of the Baltic Sea Area, the presence of Paleozoic sedimentary basins and Cambrian reservoirs, located deeper than 800m below the seabed, presents promising candidates for CO2 storage sites and, there are also offshore facilities in this region, such as those of LOTOS Petrobaltic S.A., which could potentially be used to develop CCS projects.

Furthermore, it is important to consider also the potential in depleted oil and gas fields, and overall, they have already a proven trap mechanism, known reservoir properties and existing infrastructure make CO2 storage in depleted hydrocarbon reservoirs a simpler and cheaper option than other forms of CO2 sequestration. In this regard, depleted gas reservoirs also represent the most straightforward, as primary recovery typically extracts up to 95% of the original gas in place, and the CO2 can be used to pressurize the reservoir back to its original pressure[85.] And storing CO2 in depleted oil and gas fields with legacy wells will reduce costs, whilst amounts stored offshore will increase them.

One of the most significant barriers to the widespread deployment of carbon capture technologies is the high associated costs, particularly in terms of equipment and energy required for the capture and compression phases of CO2. Therefore, integrating CCS projects in industrial clusters, including sectors like steel manufacturing, cement production, hydrogen and petrochemicals, becomes advantageous. In pursuing this initiative, attention should extend to critical aspects such as evaluating public communication and community acceptance, as well as harmonizing legal frameworks and regulations to facilitate efficient operations and compliance. These considerations can significantly favor the establishment of industrial CCS hubs and clusters, leading to a noteworthy reduction in the unit cost of CO2 storage through economies of scale. Moreover, such integrated projects offer commercial synergies that effectively mitigate investment risk. Consequently, these industrial CCS hubs and clusters can play a strategically important role in climate change mitigation.

Finally, CCS can remain theoretical without a thorough assessment of CO2 behavior and the recognition that CO2 injection involves unique pressure dynamics in the reservoir, which behave differently, as the relationship between dissipation and injection must be balanced. Therefore, in the field of pressure understanding, modelling tools play an imperative role, as reservoirs are not isolated systems, and the rate at which pressure dissipates in the vicinity of CO2 injection is a vital safety consideration. Thus, reservoir properties play a key role, as lower permeability makes CO2 dissipation slower, while higher permeability makes dissipation of CO2 from the reservoir faster.

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