Chapter

Carbon Capture and Storage (CCS): Geological Sequestration of CO_2

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Abstract

The European Union greenhouse gas emission reduction target can be achieved only by applying efficient technologies, which give reliable results in a very short time. Carbon capture and storage (CCS) into geological formations covers capturing CO_2 at the large point sources, its transportation and underground deposition. The CCS technology is applicable to different industries (natural gas processing, power generation, iron and steel production, cement manufacturing, etc.). Due to huge storage capacity and existing infrastructure, depleted hydrocarbon reservoirs are one of the most favourable storage options. In order to give overall cross section through CCS technology, implementation status and other relevant issues, the chapter covers EU regulation, technology overview, large-scale and pilot CCS projects, CO_2-enhanced oil recovery (EOR) projects, geological storage components, CO_2 storage capacity, potential CO_2 migration paths, risk assessment and CO_2 injection monitoring. Permanent geological sequestration depends on both natural and technical site performance. Site selection, designing, construction and management must ensure acceptable risk rates of less than 1% over thousands of years.

Keywords: carbon capture and storage (CCS), geological sequestration, enhanced oil recovery, trapping mechanisms, risk assessment, monitoring

1. Introduction

Global warming issue and commitments towards reducing greenhouse gas emissions of at least 40% in 2030 and up to 95% in 2050 compared to 1990 level have initiated the development of certain strategies for CO_2 removal from the atmosphere, which recognised storage in underground formations as a most practical and suitable option. Although potential underground formation could be in the form of depleted oil and gas fields, deep saline formations or deep unmineable coal seams, commercial implementation is only possible if acceptable risk level is ensured. Huge practice, existing infrastructure and remaining storage capacities are the most important advantages of using depleted hydrocarbon reservoirs for those purposes. Furthermore, residual oil production, when carbon capture and storage is connected to enhanced oil recovery, is additional initiative. On the other hand, lack of research when it comes to other storage options requires different research programs to be performed in order to confirm projects feasibility and the safety of technology.

Formation storage possibility has to be defined through characterisation and assessment of potential storage complex, comprising data collection, static and dynamic modelling, sensitivity characterisation and risk assessment. Underground storage must meet relevant capacity and injectivity requirements, while storage efficiency depends on different physical and geochemical trapping mechanisms, which occur during the storage lifecycle [1]. Nevertheless, permanent storage is ensured by existing geological and equipment barriers; a certain risk of CO_2 migration has to be considered, assessed and controlled [2]. Special attention must be paid to the injected fluid migration issue, which implies identification of potential migration routes, such as faults and fractures, wells (active and abandoned) and seal rocks [3, 4]. In line with legal requirements, performed risk analysis and established monitoring plan, the effectiveness of storage complex has to be constantly evaluated. Comprehensive monitoring, which covers CO_2 plume tracking and surrounding environment monitoring, represents a very important part of the overall risk management strategy.

2. CCS deployment legal background

The international climate goal, set within the United Nations Framework Convention on Climate Change (UNFCCC) in Paris in 2015, seeks the limitation of the average temperature increase to below 2°C, compared to preindustrialisation reference level. That quite ambitious climate target depends on economy decarbonisation through increasing energy efficiency, enhancing the share of renewables in energy production and reducing greenhouse gas emissions. In order to achieve low carbon economy, the EU strategy targeted greenhouse gases emission reduction by 40% by 2030, and up to 95% by 2050 compared to the base year (1990) level [5, 6].

However, despite the efforts to enhance "green energy" sources, the society is still largely dependent on fossil fuels and it is evident that conventional carbon technologies cannot be removed easily from the industry processes in close future. Therefore, a systematic approach is needed.

The EU Directive 2009/31/EC on the geological storage of carbon dioxide [7] entered into force in 2009, establishing a legal framework for safe CO_2 geological sequestration in Europe. The Directive attempted to prevent any significant CO_2 leakage risk or damage to health and/or the environment by setting requirements for the entire storage cycle. It excludes potable water aquifers and tectonically active zones as potential sites for permanent disposal of CO_2.

The EU-requested emission reductions are expected to be achieved through the main instrument—the European Emission Trading Scheme (EU ETS) (**Figure 1**). The system is based on the EU Directive 2003/87/EC, establishing a scheme for greenhouse gas emission allowance trading within the Community [8]. It operates on a cap and trade principle, which considers behaviour in line with installations emission permits and market trading of EU emission unit allowances. Temporarily, the third phase of the system is operational (2013–2021). The main issue at the beginning of the third trading period was the imbalance between allowances supply and demand on the market, caused mainly by lower industrial activity. In order to overcome such unsustainable situation and increase the CO_2 price, which would encourage system participants to apply emission reduction measures comprising the CCS projects, a radical legislation revision was needed. It included the increase in the allowances reduction factor, auctioning the postponement of 900 million of allowances and establishment of the market stability reserve [9].

Carbon capture and storage technology is often observed as a transitional solution to low-carbon economy, due to possibility of further usage of fossil fuels in power

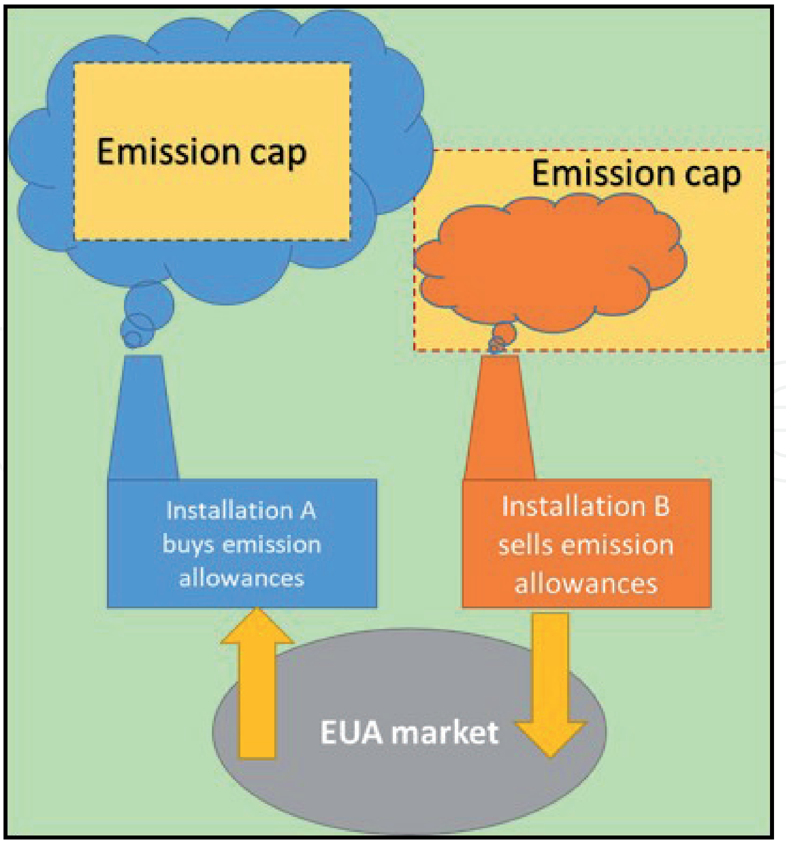

Figure 1.
The European Emission Trading Scheme (EU ETS) principles.

generation while simultaneously reducing CO_2 emission [10]. Since the demanding climate goals require about 4000 Mt/y of CO_2 to be removed from the atmosphere by 2040 [11], a lot of further effort has to be invested. Inclusion of CCS in clean development mechanisms (CDMs) is one step ahead in its global deployment [12].

The success of the CCS project is only possible if stable, clear and efficient regulatory framework and supporting public acceptance are ensured [13]. A political decision on CCS is influenced by different factors, such as national CO_2 emission level and emission reduction commitments, available storage capacity and public awareness. This means that most of the research and development activities occur in the states with the highest emissions intensity (e.g., Germany, the UK, Italy, France, Spain, the Netherlands and Norway). On the other hand, strong local public resistance (e.g., in Denmark, Germany, the UK, Poland and the Netherlands) resulted with the cancellation of more projects and the postponement of CO_2 storage acceptance [14].

Still, most of the EU Member States transposed the Directive without any restrictions and continue to support research in order to improve the technology (**Figure 2**).

Since the CCS initiatives in the EU originate from climate changes mitigation intention, projects in North America are mostly connected to the EOR activities, with CO_2 sales as a major incentive. Viability of such projects is strongly dependent on the oil price.

Due to instability of market oil prices, financial support is crucial to provide a certain level of certainty. CCS projects are supported by different policies at Federal, State and local levels. The Department of Energy (DOE) provides financial assistance and grants in line with the Energy Improvement and Extension Act (2008) and the American Recovery and Reinvestment Act (2009) [13]. In EU, additional funding may refer to the EU Energy Program for Recovery (EEPR), the NER300, FP7 or some national government funding schemes [15]. The ETS Innovation Fund is a new EU funding scheme, scheduled for 2021. Based on the

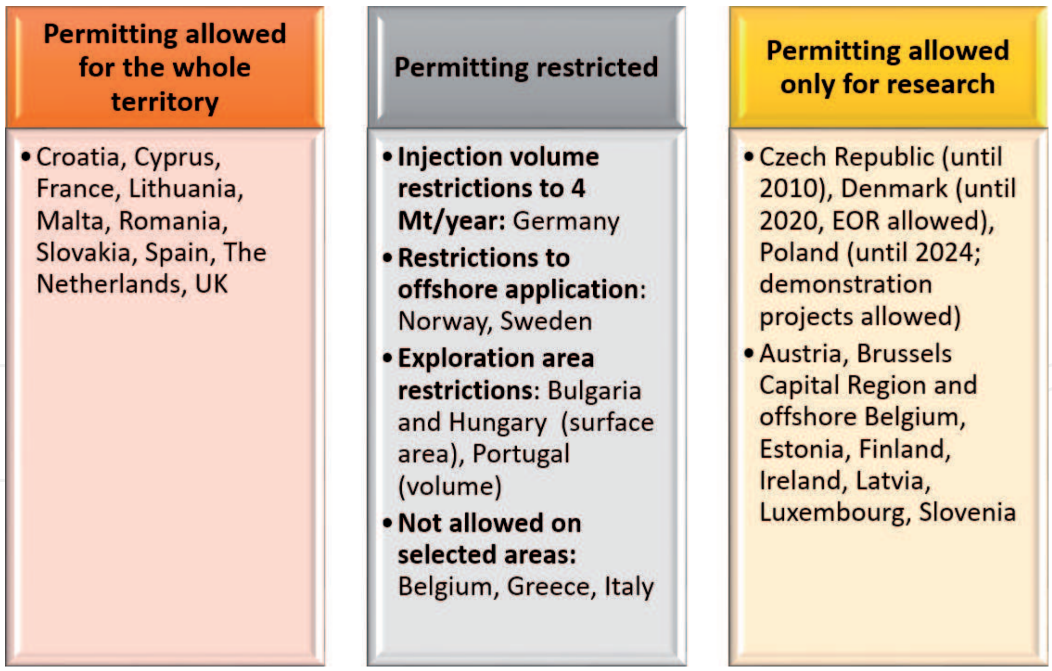

Figure 2.
CO_2 storage permitting in European countries [14].

NER300 platform, it is going to support innovative low-carbon technologies, including CCS demonstration projects, by monetizing 400 million of CO_2 emissions unit allowances (EUA) from the New Entrants' Reserve [16].

3. CCS technology overview

Capturing CO_2 from the exhaust gases generated by different energy intensive industries (e.g., power generation, oil refineries or iron, steel and cement production), its transportation and permanent sequestration are fundamental parts of the CCS processes.

Exhaust gas is a mixture, which, besides nitrogen, steam, particulate matters and some other pollutants, contains only a small share of CO_2 (3–15%). That means that pure CO_2 must be extracted using different capture technologies: (a) pre-combustion capture system, (b) post-combustion capture system, (c) oxyfuel combustion system and (d) industrial separation (**Figure 3**). Technology selection depends on the concentration of CO_2 in the gas stream, pressure and fuel type [1, 17].

A **pre-combustion** capture processes comprise adding steam or oxygen to primary fuel, which results in synthesis gas (gas containing H_2 and CO) production. Further reaction of CO and steam in the shift reactor produces a mixture of H_2 and CO_2 in concentration between 5 and 15% volume. After separation, CO_2 is extracted by physical or chemical adsorption. In a **post-combustion** capture system, CO_2 is extracted from nitrogen after combustion by different physical or chemical solvents, or it is separated by adsorbents or membranes. This common technology can be an upgrade to existing thermal power plants and different industrial facilities, etc. An **oxyfuel combustion** capture system considers oxygen addition in the process of fossil fuel combustion, resulting in more concentrated CO_2 stream (more than 80% volume), which is prone to easier separation. Although this technology is simple and highly efficient in CO_2 removal, wide application is still prevented by the high cost of pure oxygen production. **Industrial separation** has had the longest usage: the CO_2, as unwanted compound, is separated in different industrial processes, comprising natural gas, hydrogen and ammonia production [1, 2, 17].

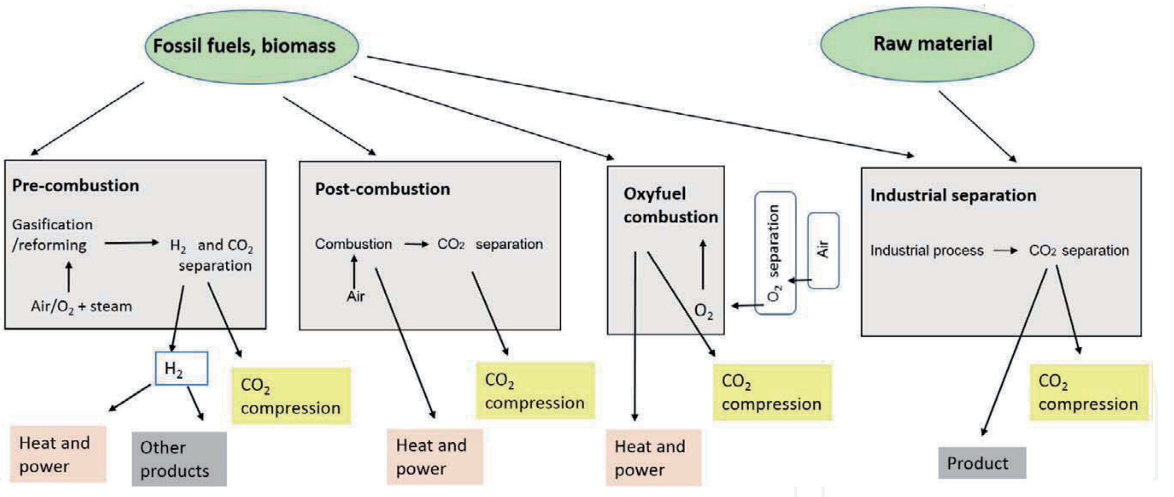

Figure 3.
Carbon capture processes [2].

The Carbon Capture R&D program has been implemented by the US National Energy Technology Laboratory (NETL) in order to develop cost-effective technologies based on different concepts (solvent, sorbent or membrane) [18].

After capturing, the CO_2 can be transported at solid, gaseous or liquid state or in the form of supercritical fluid. Although ships can be used, pipeline transport is often preferred as the most practical and the cheapest solution.

Application of CCS compared to other carbon sequestration options is preferred due to costs. The cost of geological storage of CO_2 depends on several factors such as the depth of the storage formation, the number of wells needed for injection and whether the project is onshore or offshore. For instance, capture system installed at fossil fuel power plant is between 15 and 75 USD/t (CO_2), where the coal-fired plants are the higher cost option. The costs are something lower in case of hydrogen, ammonia production or gas sweetening (from 5 to 55 USD/t (CO_2), while application to other industries is even more expensive, with costs between 25 and 115 USD/t (CO_2). Taking into consideration the costs of transportation of 5–40 Mt/y CO_2 by pipeline, which are on the level of 1–8 USD/t (CO_2), and geological storage and monitoring costs, which range from 0.6 to 8 USD/t (CO_2), it can be concluded that capture costs make up the majority of the price. However, considering the largest emissions belong to the fossil fuel power plants, it is important that research priority is focused on developing cost-effective capture technologies for power sector [19].

4. CCS projects

As is the case with all new technologies, implementation of CCS is facing different obstacles, which prevent a shift from the project planning phase to construction and operation phase. Commercial scale implementation requires a certain level of experience in technical, operational and economic feasibility of projects, which is substantial for risk decreasing and cost reduction.

Several decades of worldwide implementation of CCS research programs have resulted in a huge amount of experience and important knowledge on carbon capture and storage technology. The data obtained during large- and small-scale projects implementation are collected by different associations. Comprehensive databases founded by, for example, Carbon Capture and Sequestration Technologies at the Massachusetts Institute of Technology (MIT) [15], Global CCS Institute [20], National Energy Technology Laboratory (NETL) [18], Zero

Emissions Platform [21], British Geological Survey [22], etc., can serve as a valuable source of information in further research and design [2].

A large-scale facility captures at least 0.8 Mt of CO_2 from a coal-based facility for power generation or at least 0.4 Mt of CO_2 from other industry on yearly basis [20].

Due to insufficient capture capacity or absence of full integration, a number of the CCS projects cannot be declared as large scale, but since they are focused on the targeted parts of the CCS chain, they contribute to the development of technology. The small-scale projects can be used for demonstration or on a pilot scale.

The Global Carbon Capture and Storage Institute database counts 23 large-scale CCS facilities both in operation and under construction, having capture capacity of approximately 30 Mt/y. Realisation of further 5 projects, which are now in advanced planning phase, as well as another 15 projects, which are in early planning, could significantly increase capture capacity by more than 60 Mt/y.

Temporarily ongoing large-scale CCS projects are located in the USA, Canada, China, Saudi Arabia, United Arab Emirates and Europe. In Europe, the lack of national policy support and negative public opinion resulted in cancellation of some of the most promising CCS projects. However, successful operation of two Norwegian large-scale projects (Sleipner and Snøhvit) is enabled by high national carbon taxation. Future CCS activities in Europe are going to be expanded to two new offshore storage projects: Norway full chain CCS and Port of Rotterdam CCUS Backbone Initiative (Porthos).

Some of CCS projects are in the advanced planning or in the early planning phase. They are going to geologically store emissions from power generation and chemical industry. As regards CO_2 capture process, high cost of oxyfuel technology is the reason that only post-combustion technology has been applied [2, 20].

According to Carbon Capture and Sequestration Technologies at MIT database, there are substantial numbers of small-scale demonstration and pilot projects worldwide applied on different industries. Most of them are performed in Asia (China, Japan and South Korea), but also and to a lesser extent in the North America and Europe [15].

4.1 CO_2-EOR projects

Production from oil reservoirs is carried out in three phases: primary, secondary and tertiary. During the *primary recovery stage*, the reservoir pressure is sufficient to force the oil to the surface and recovery factor is typically 5–15%. During exploitation, reservoir pressure decreases and at one point, it becomes insufficient to force the oil to the surface. After that, *secondary recovery* methods are applied. They include water injection or natural gas reinjection to increase the reservoir pressure or gas lift (injection of gas into an active well to reduce the density of fluid in the well). The typical recovery factor from secondary operations is about 30%. Further increase of oil production is possible by the application of *tertiary oil recovery methods* or enhanced oil recovery (EOR) methods (including thermal recovery, chemical flooding and miscible gas injection), which increase the mobility of oil. Tertiary recovery provides additional production of 5–15% of oil.

CO_2-EOR is one of the tertiary oil recovery methods. The petroleum industry has been injecting CO_2 into partially depleted oil reservoirs for dozens of years. It is based on injection of CO_2 and usually water into the oil reservoir with the aim to enhance oil recovery by maintaining pressure in the reservoir and by improving oil ability to flow in the direction of the production well (**Figure 4**).

The CO_2 is produced along with the oil and then recovered and reinjected to recover more oil. When the maximum amount of oil is recovered from the reservoir, the CO_2 is then “sequestered” in the underground geologic zone that formerly contained oil and the well is shut in, permanently sequestering the CO_2.

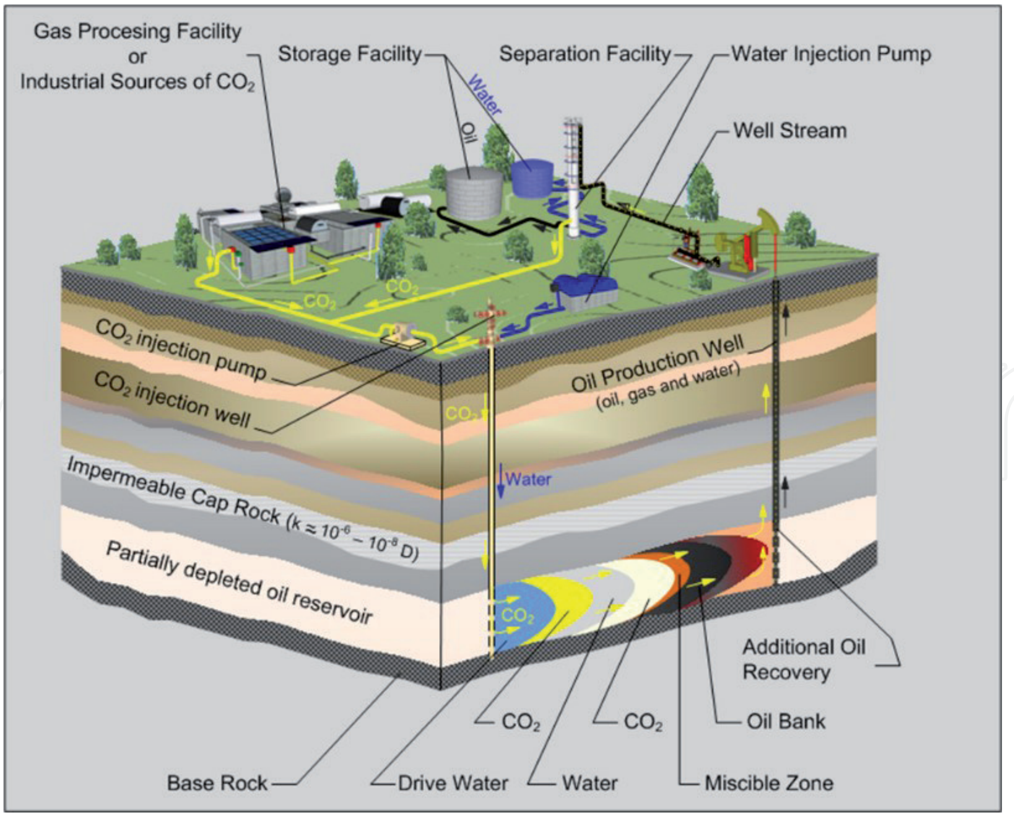

Figure 4.
The process of CO_2 and water injection in order to improve oil recovery [23].

EOR sites offer several advantages such as (1) well-understood geology and geologic seals, (2) proven capacity to hold volumes of CO_2 and (3) existing infrastructure such as surface facilities, pipelines, injection and monitoring wells.

CO_2-EOR can be employed onshore and offshore. It could lead to negative storage costs of 10–16 US$/t CO_2 for oil prices of 15–20 US$ per barrel and more for higher oil prices [1].

CO_2-EOR was first attempted in 1972 in Scurry County, Texas. In the 1970s, Shell was one of the first companies to inject naturally occurring carbon dioxide (CO_2) to increase oil recovery from fields in Texas, USA [24].

While initial CO_2-EOR developments used naturally occurring carbon dioxide deposits, technologies have been developed to inject CO_2 created as by-products from industrial operations. For example, Dakota Gasification Company's plant in Beulah, North Dakota, is producing CO_2 and delivering it by a 204-mile pipeline to the Weyburn oil field in Saskatchewan, Canada.

According to the CCS institute database, within the last 2 years, four large-scale projects were launched. Large-scale Emirates Steel Industries (ESI) CCS project running in Abu Dhabi represents the first application of CCS to iron and steel industry, where 0.8 Mt/y of CO_2 is injected underground for the purpose of hydrocarbon recovery [2, 20]. The Illinois Industrial CCS project enabled the capture of 1.0 Mt/y of CO_2 generated at the corn to ethanol facility in Decatur (Illinois, USA) and its permanent geological disposal, while the Petra New Carbon Capture project in Texas stands out for the largest power plant post-combustion CO_2 capture system. Captured gas at 1.4 Mt/y capacity is transported by pipeline and injected for EOR purposes. Another recent example where CO_2 is injected to improve oil recovery is the Chinese CNPC Jilin Oil Field CO_2 EOR project. After 12 years of testing, commercial operation started in 2018. The CO_2 source is at a natural gas processing plant. Capturing capacity is on the level of 600,000 t/y of CO_2.

In Croatia, the first application of CO_2-EOR started in October 2014 by the INA—Oil Industry Ltd. oil company. The project's aim is to enhance hydrocarbon production by alternating injection of carbon dioxide and water into mature oil fields Žutica and Ivanić [25]. The *EOR* project involves dehydration, compression and transportation of 600,000 m^3/day of CO_2 by 88 km long gas pipeline (20 in.) from the Gas Processing Facilities Molve to the Fractionation Facilities Ivanić Grad.

After its compression and liquefaction at the location of Fractionation Facilities Ivanić Grad, CO_2 is transported by pipeline at high pressure (200 bar) to the injection wells of the Ivanić and Žutica fields, in quantities of 400,000 and 200,000 m^3/day, respectively. During the period of 25 years, which is the expected duration of the project, about 5×10^9 m^3 of CO_2 will be injected in the reservoirs of these fields. That will result in additional hydrocarbon production (3.4×10^6 t of oil and 599×10^6 m^3 of gas). Due to geological and physical conditions, about 50% of injected CO_2 will be permanently trapped in the reservoirs, while another 50% of CO_2 will be produced together with associated gas. Currently, the solution regarding the further use of CO_2, which will be extracted from associated gas at the location of the Compressor Station Žutica, is being developed. To implement the EOR project, it was necessary to carry out workover operations and construction modifications of existing wells. Keeping in mind corrosive features of CO_2, special attention was paid to the selection of surface and underground equipment.

According to Heidug et al. [26], CO_2-EOR practice can be modified to deliver significant capacity for long-term CO_2 storage. EOR expansion to storage of CO_2 can be achieved through at least four major activities: (1) additional site characterisation and risk assessment to evaluate the storage capability of a site, (2) additional monitoring of vented and fugitive emissions, (3) additional subsurface monitoring and (4) changes to field abandonment practices.

5. Geological storage complex and surrounding area characterisation

Potential sites for geologic storage are depleted oil and gas fields, deep saline formations and deep unmineable coal seams. According to EU Directive 2009/31/EC [7], the characterisation and assessment of the potential storage complex, including the cap rock and surrounding area, including the hydraulically connected areas, should be carried out in three steps according to best practices at the time of the assessment: (1) data collection, (2) building the three-dimensional static geological earth model and (3) characterisation of the storage dynamic behaviour, sensitivity characterisation and risk assessment (**Figure 5**).

Collecting data about the storage complex and the surrounding area is very important because it serves as a base for making their volumetric and three-dimensional (3-D) static earth model.

In the first step, for describing the storage complex, it is necessary to collect information about its characteristics. In the second step, based on the collected data and using computerised reservoir simulators, a three-dimensional static geological earth model of the candidate storage complex, including the cap rock and the hydraulically connected areas and fluids, is built. It characterises the storage complex.

In the third step, the characterisations and assessment of storage complex are based on dynamic modelling, comprising a variety of time-step simulations of CO_2 injection into the storage site using the three-dimensional static geological earth model(s) constructed during the second step. The simulations are based on altering parameters in the static geological earth model(s) and changing rate functions and assumptions in the dynamic modelling exercise. Any significant sensitivity should be taken into account during risk assessment.

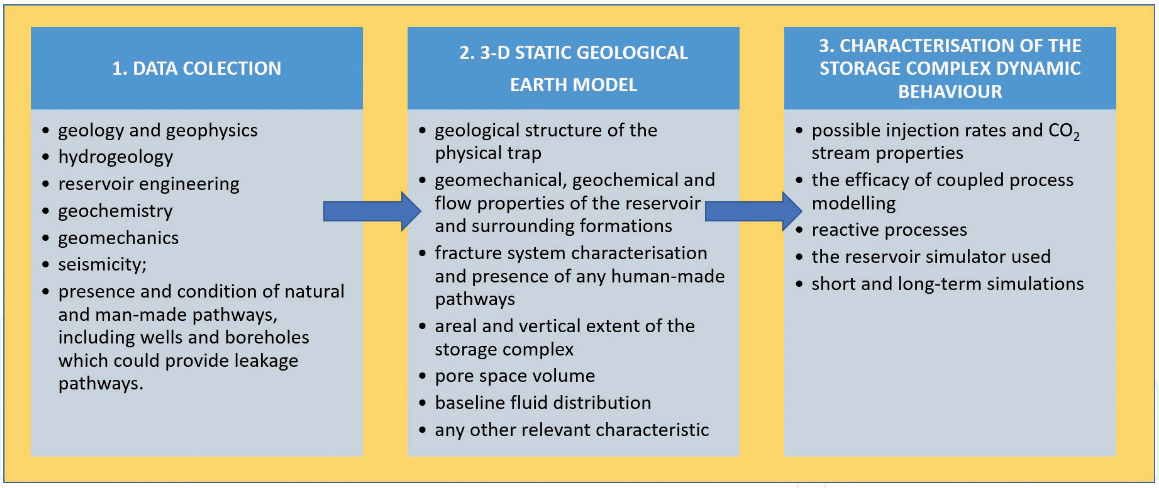

Figure 5.
The characterisation and assessment of the storage complex.

6. Potential CO_2 leakage pathways

The injected CO_2 could leak or migrate from CO_2 storage formation upwards (into upper rocks, aquifer or to atmosphere) if the following conditions are present: (a) CO_2 gas pressure exceeds capillary pressure and passes through siltstone, (b) free CO_2 leaks from siltstone into upper aquifer up the fault, (c) CO_2 escapes through a "gap" in the cap rock into a higher aquifer, (d) injected CO_2 migrates up the dip, increases reservoir pressure and permeability of fault, (e) CO_2 escapes via poorly plugged new or old abandoned wells, (f) natural flow dissolves CO_2 at CO_2/water interface and transports it out of closure and (g) dissolved CO_2 escapes to the atmosphere or into the ocean. **Figure 6** shows the migration paths of injected CO_2 from storage formation towards surface through a fracture in the cap rock, along fault zones and via poorly cemented active or abandoned wells.

The integrity of the cap rock is assured by an adequate fracture gradient and by sufficient cement around the casing across the cap rock and without a micro-annulus. The permeability and integrity of the cement will determine how effective it is in preventing leakage.

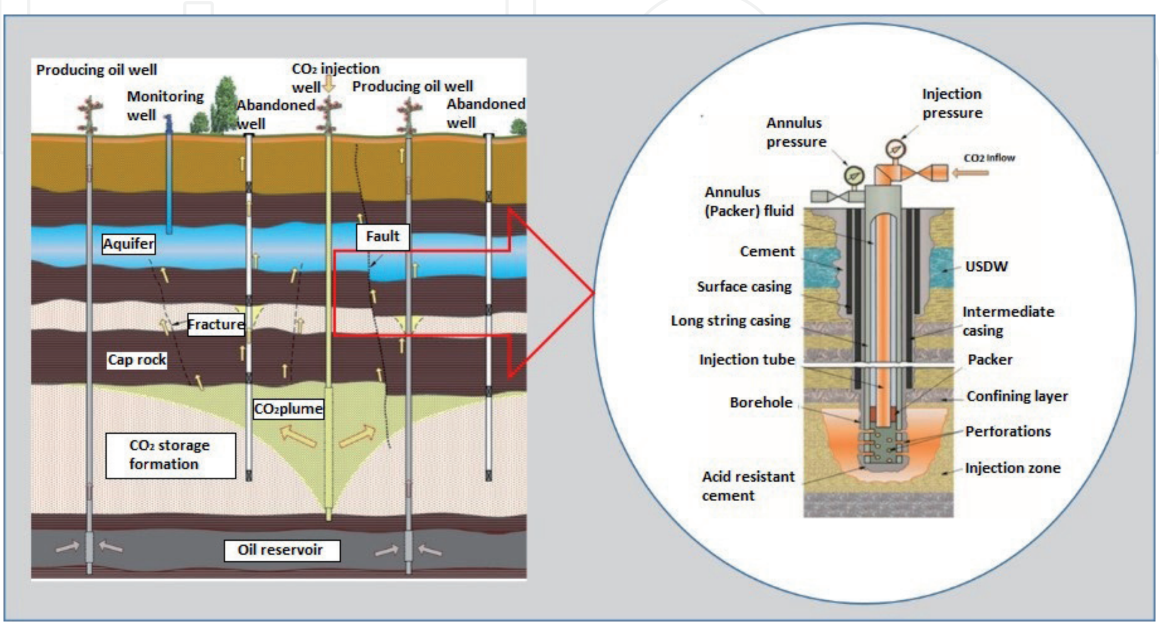

Figure 6.
Potential leakage pathways of injected CO_2 and CO_2 injection well design (modified after references [27, 28]).

Potential leakage pathways along an active injection well and/or an abandoned well include leakage: through deterioration (corrosion) of the tubing, around packer, through deterioration (corrosion) of the casing, between the outside of the casing and the set cement, through the deterioration of the set cement in the annulus (cement fractures), leakage in the annular region between the set cement and the formation, through the cement plug and between the set cement and the inside of the casing [4, 29, 30].

A key concept related to the performance of an injection well, and the prevention of CO_2 migration from the injection zone through an active or abandoned well, is its mechanical integrity (internal and external). Internal mechanical integrity of the well is achieved by ensuring that each of the components of the well is constructed using corrosion-resistant materials such as 316 stainless steel, fibreglass or lined (with glass reinforced epoxy, plastic or cement) carbon steel for casing and tubing. External mechanical integrity of the well is achieved by successful primary cementing operation with the use of CO_2-resistant cement, resulting in a cement sheath to bond and support casing and provide zonal isolation. The permeability and integrity of the set cement will determine its effectiveness in preventing CO_2 leakage.

6.1 CO_2 trapping mechanisms

The possibility of potential leaks of CO_2 is one of the largest barriers to large-scale CCS although well-selected storage sites are likely to retain over 99% of the injected CO_2 over 1000 years. Four different storage mechanisms keep the supercritical CO_2 securely stored inside the CO_2 storage formation: structural/stratigraphic (or physical) trapping, (2) solubility trapping, (3) residual trapping and (4) mineral trapping [1, 31]. The most important CO_2 storage mechanism during an injection process of several decades is structural/stratigraphic trapping. The other three mechanisms enable the trapping of CO_2 over a long period of time [1]. The effectiveness of geological storage depends on a combination of physical and geochemical trapping mechanisms. **Figure 7** presents four injection scenarios.

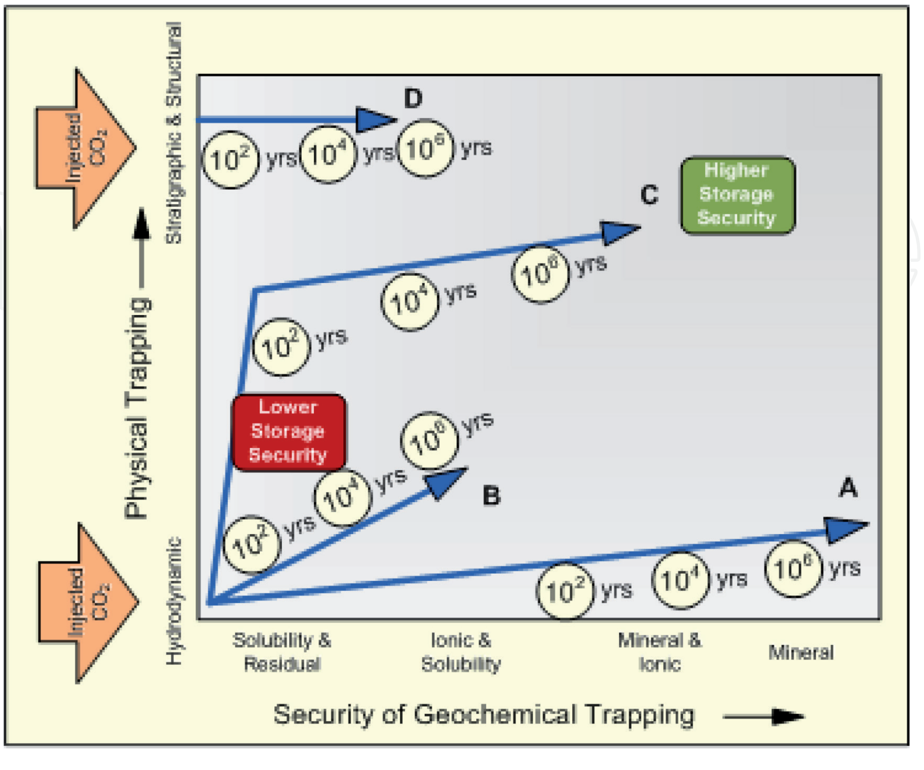

Figure 7.
The influence of a combination of physical and geochemical trapping mechanisms on CO_2 security storage (modified after reference [1]).

Injection scenarios A, B and C show injection into hydrodynamic traps, essentially systems open to lateral flow of fluids and gas within the injection formation. Scenario D represents injection into a physically restricted flow regime, similar to those of many producing and depleted oil and gas reservoirs. The level of security is proportional to the distance from the origin. Dashed lines are examples of million-year pathways.

As time passes and more CO_2 is injected, the more secure trapping mechanisms keep CO_2 in place, leading to increased security of storage [31].

7. Storage capacity

According to Bradshaw et al. [32], capacity calculation can be threefold, depending on the required category level: *theoretical, realistic and viable capacity*. *Theoretical capacity* considers whole reservoir pore space available for storage, or saline aquifer, which is saturated with salt water having maximum dissolved CO_2. In practice, different technical and economic restrictions prevent storage quantities to reach the level of theoretical capacity. *Realistic capacity* takes into consideration reservoir quality parameters (porosity, permeability, seal, depth, pressure, stress regimes, etc.) as important indications of technical viability. *Viable capacity* includes legal and regulatory limitations and considers social and environmental aspects of the selected location while connecting the CO_2 source with the nearest storage site.

Storage capacity can be generally expressed as the quantity of CO_2 that may be injected and stored in the geological layers.

According to the study of the Task Force for Review and Identification of Standards for CO_2 Storage Capacity Estimation of Carbon Sequestration Leadership Forum (CSLF), the regional CO_2 storage capacity in structural and stratigraphic traps (Eq. (1)) can be calculated using a residual water saturation [33, 34]:

$$V_{CO2t} = V_{trap} \cdot \Phi(1 - S_{wirr}) = A \cdot h \cdot \Phi\,(1 - S_{wirr}) \tag{1}$$

where V_{CO2t}, theoretical storage volume CO_2 (m^3); V_{trap}, trap volume (m^3); Φ, average trap porosity (−); S_{wirr}, irreducible water saturation (−); A, trap area (m^2); h, average trap thickness (m).

Similar approach is used by the United States Department of Energy (DOE). It takes into account the porous space of the entire layer of saturated water and does not distinguish between CO_2 storage mechanisms. It takes into account the storage efficiency coefficient, which reflects the size of the space that can be filled with CO_2. The coefficient encompasses a wide variety of variables, ranging from petrophysical reservoir properties (porosity and permeability) to the sweep efficiency and effective porosity. According to the US DOE, for the regional salt water aquifers, the coefficient of storage efficiency is suggested to be 2% [35, 36].

The storage capacity of depleted hydrocarbon fields [Eqs. (2) and (3)] can be calculated from cumulative production and reserve data following the methodology described in [37].

$$M = \rho_{\cdot\, CO_{2r}} \left(R \cdot \mathrm{f} \cdot \mathrm{N} \cdot B_{\mathrm{fo}} - W_{\mathrm{i}} + W_{\mathrm{p}}\right) \tag{2}$$

$$M = \rho_{\cdot\, CO_{2r}} \cdot R\mathrm{f}\left(1 - F_{\mathrm{ig}}\right) \cdot\ G \cdot B_{\mathrm{g}} \tag{3}$$

where M, reservoir capacity for CO_2 storage (kg); ρ_{CO2r}, CO_2 density at reservoir conditions (kg/m^3); R_f, recovery factor (−); N, original oil in place (m^3); B_o, oil formation volume factor (−); W_i, water injection (m^3); W_p, water production (m^3); F_{ig}, gas injection (m^3); G, original gas in place (m^3) and B_g, gas formation volume factor (−).

Theoretical storage capacity obtained by these equations takes into account the estimated recoverable hydrocarbon reserves as the product of original hydrocarbon in place and recovery factor. For the effective capacity, it is necessary to consider some additional factors such as the macroscopic displacement efficiency, buoyancy, reservoir heterogeneity, water saturation, reservoir drive, etc.

Although the sweep efficiency has often been ignored in the case of depleted hydrocarbons fields, instead of the total amount, only 75% replacement of original oil or gas in place can be expected [38, 39].

The very first global assessment of CO_2 storage capacity was made back to the 1990s. Koide et al. [40, 41] assessed CO_2 storage capacity for deep saline aquifers on the level of 320×10^9 t. According to Van der Meer [42], it was estimated to 425×10^9 tons, calculation made by Ormerod et al. [43] was on the level of 790×10^9 t CO_2. Hendricks and Blok [44] reported storage capacity of 150×10^9 t, which was mainly related to depleted hydrocarbon reservoirs [25].

Preliminary estimation of CO_2 storage capacity for European deep aquifers and hydrocarbon reservoirs was done within the framework of the projects GESTCO, CASTOR and GeoCapacity, financed under the 5th and 6th Framework Program for Research and Technological Development [45]. In the case of deep aquifers, a simplified methodology based on a volumetric approach was applied, calculating with average values for layer thickness, temperature, pressure and porosity for each storage location. Storage assessment of hydrocarbon reservoirs used material balancing method, assuming that extraction of hydrocarbon releases certain pore volume available for CO_2 injection. The EU GeoCapacity project estimated CO_2 storage capacity to be on the level of 127 Gt, covering saline formations (97 Gt), hydrocarbon fields (20 Gt) and coal seams (1 Gt). The storage capacity was evaluated in 17 countries as sufficient at national level, while in one country (Norway), it was concluded that cross-border storage is possible. However, storage capacity was defined as "insufficient" in five countries [14].

7.1 CO_2 storage resources classification

The Society of Petroleum Engineers (SPE) published the document entitled *CO_2 Storage Resources Management System (SRMS)*, prepared by its subcommittee of the Carbon Dioxide Capture, Utilization and Storage Technical Section (CCUS), which establishes technically based capacity and resources evaluation standards [45]. This document is based on the SPE PRMS (*The Petroleum Resources Management System*), which is developed by SPE Oil and Gas Reserves Committee and used internationally within the petroleum industry for consistent and reliable definition, classification and estimation of hydrocarbon resources.

SPE CO_2 SRMS provides a consistent approach to estimating storable quantities of CO_2, evaluating development projects and presenting results within a comprehensive classification framework. The SRMS classification scheme is based on the accessible pore volume in a geologic formation in which CO_2 could be stored. It is intended for use in geologic formation completely saturated with brine such as saline formations or saline aquifers and depleted hydrocarbon fields without hydrocarbon production.

CO_2 storage resources are defined as the quantity (mass or volume) of CO_2 that can be stored in a geological formation and include all quantities of naturally occurring pore volume potentially suitable for storage within underground formations—*discovered* and *undiscovered* (accessible and inaccessible storage resources), as well as those quantities already used for storage (stored resources). The SPE storage resources classification system is shown in **Figure 8**.

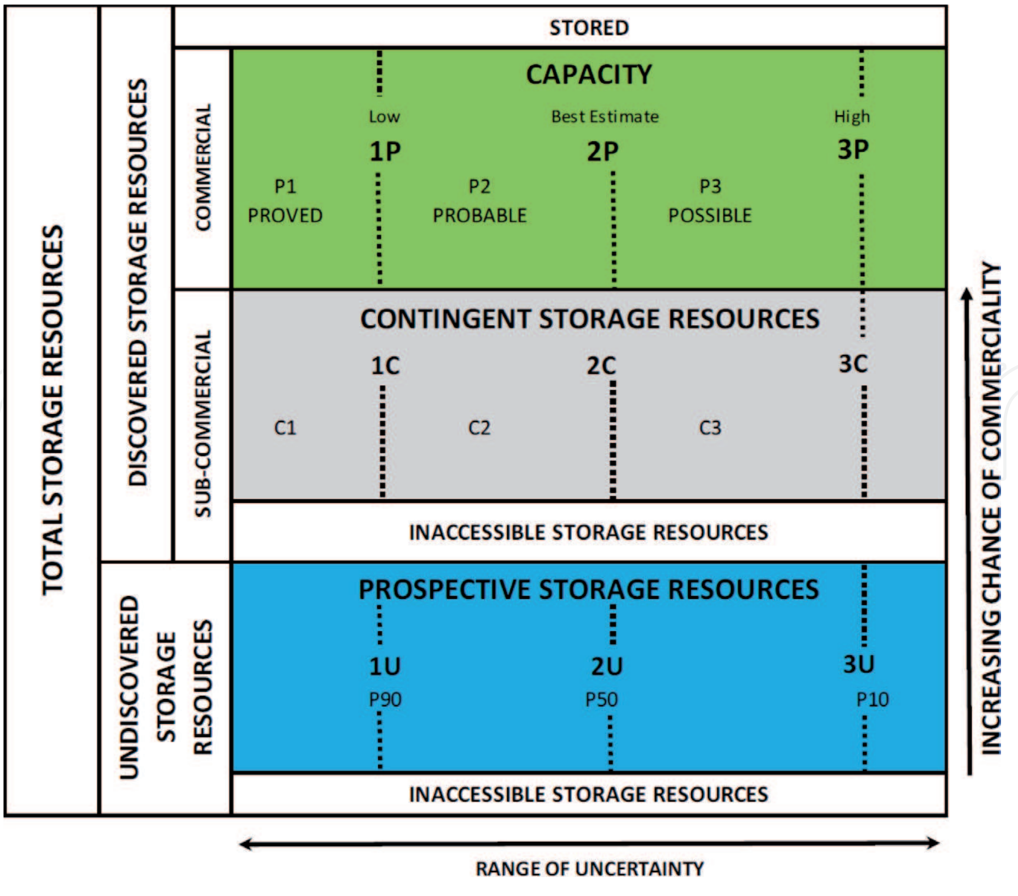

Figure 8.
CO_2 resources classification framework [45].

8. Risk assessment

The risks associated with underground CO_2 storage depend on many factors, including used infrastructure, type of reservoir dedicated to storage, geological characteristics of selected layers, cap rock and stratigraphic heterogeneity, geomechanical properties of rocks, existence of other wells, method of well abandonment experience, etc. EU CCS Directive is developed on the basis of a risk-based approach for safe storage and leakage. Therefore, it is necessary, before the application of CCS, to determine whether identified risks are acceptable. The significant risk of CO_2 leakage could not be permitted under the EU CCS Directive.

The risk assessment should comprise, among other things, hazard characterisation, exposure and effects assessment and risk characterisation. Characterisation of the hazard is carried out by characterising the potential leakage from the storage complex, as established by the dynamic modelling. It should cover the full range of potential operating conditions to test the security of the storage complex.

Many papers are published with the aim of assessing the risk of CO_2 storage, and various methodologies are currently applied to risk assessment of geological CO_2 storage (e.g., [3, 4, 28, 46–48]).

Figure 9 shows risk concept profiles for a large CCS project over time. The blue line represents a project with the pressure in storage formation increasing during CO_2 injection and decreasing after injection stops. The red line represents potential risk profile over time. The potential risk of failure and CO_2 leakage increases during the injection, and after the injection stops, it decreases. Secondary risk increases depend on local geochemical risks of transport processes.

Jewell and Senior [51] described scenarios and parameters for potential leakage from active (CO_2 injection well, observation well or water extraction well) and

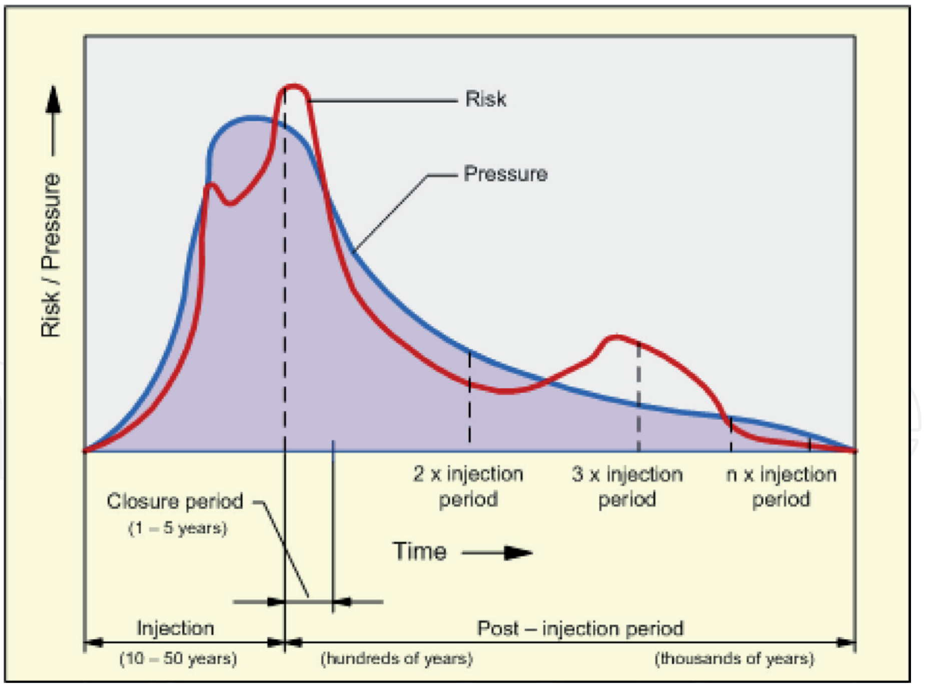

Figure 9.
Risk concept profiles for a large CCS project over time (modified after references [3, 49]).

Parameters	**Scenarios**			
	Active CO_2 injection well		**Abandoned well**	
	Low-level leakage: via CO_2 injection well	**Worse case: blow out on CO_2 injection well after failure of initial well control activities**	**Low-level leakage: via abandoned well**	**Worse case: complete breakdown of abandonment plugs in old well**
Probability of leakage	0.0001–0.001	0.00001–0.0001	0.0012–0.005	—
Potential CO_2 leakage rates (t/day)	0.1–10.0	5000.00	0.60–6.00	1000.00
Duration	0.5–20 years (until well abandoned)	3–6 months	1–100+ years	3–6 months
Potential amount of CO_2 leakage (t)	18–73,000.00	$(0.45–0.9) \times 10^6$	220–220,000.00+	90–180,000.00
% CO_2 stored (200 million tonnes case)	0–0.036	0.225–0.45	0.0001–0.1+	0.045–0.09
Remarks	Data represent the best efforts to represent leakage scenarios and risks in the North Sea for a storage scheme:			
	With 5 CO_2 injection wells, 20-year injection period and 200 million tonnes of stored CO_2.		With 6 abandoned wells, probability of leakage over 100 years and 200 million tonnes of stored CO_2.	

Table 1.
Scenarios and parameters for potential leakage from active and abandoned wells (modified after reference [50]).

abandoned wells as well as via primary cap rock and fault to assist in the development of a common understanding of CO_2 leakage and associated liabilities in the North Sea (**Tables 1** and 2).

Parameters	Scenarios			
	Primary cap rock	Fault		
	Migration through primary rock	Low flux: vertical migration through existing faults	Moderate flux: vertical migration through existing faults	High flux: migration through fault activated and enhanced by injection
Probability of leakage	Negligible	Not calibrated—highly site specific		
Potential CO_2 leakage rates (t/day)	Very low flux rates	1–50	50–250	1500.00
Duration	100–1000 years to breakthrough	1–100 years for low flux; excludes remediation	1–5 years; includes remediation	1–5 years; includes remediation
Potential amount of CO_2 leakage (t)	Very low	$(0–1.8) \times 10^6$ (100-year flux); no remediation	$(0.018–0.46) \times 10^6$ including remediation	$(0.55–2.7) \times 10^6$ including remediation
% CO_2 stored (200 million tonnes case)	N/A	0–0.9	0.0009–0.23	0.275–1.37
Remark	—	Data represent the best efforts to represent leakage scenarios and risks in the North Sea if faults are present.		

Table 2.
Scenarios and parameters for potential leakage via primary cap rock and fault (modified after reference [50]).

In case of leakages or significant irregularities, the operator is obliged to immediately notify the competent authority and take the necessary corrective measures, including measures related to the protection of human health. The purpose of corrective measures is to prevent or stop the escape of CO_2 from the storage formation, to ensure safe geological storage and to manage the risks during the lifespan of the project and afterwards. According to the EU CCS Directive and EC Guidance Document 2, corrective measures include but are not limited to (1) limiting CO_2 injection rates or stopping injection and pressure buildup, (2) reducing the reservoir pressure by extracting CO_2 or water from the storage complex, close to an identified leakage area or applying peripheral extraction, (3) sealing areas of leakage such as identified fault or cap rock leakage pathways by injecting low permeability materials, creating a hydraulic barrier that stops CO_2 migration in sensitive areas by increasing the pressure in the above formations, (4) well remediation for active wells (for example, repair of wellhead, damaged tubing or collapsed casing; packer replacement, squeeze cementing and so on) and (5) well control, including killing the well by injecting heavy fluids and after that cementing the well or drilling a new well to intersect and plug the leaking well.

9. CO_2 injection monitoring

Monitoring of injection facilities, storage complex (including where possible the CO_2 plume) and, where appropriate, the surrounding environment present a very important part of the overall risk management strategy for geological storage projects. It should be based on a monitoring plan established according to the risk assessment analysis.

	Preoperational	Operational	Closure
Basic monitoring	**Monitoring program**		
	Well logs	—	—
	Wellhead pressure	Wellhead pressure	—
	Formation pressure	—	—
	Injection- and production rate testing	Injection- and production rates	—
	Atmospheric-CO_2 monitoring	Wellhead atmospheric-CO_2 monitoring	—
	Seismic survey	Seismic survey	Seismic survey
	—	Microseismicity	—
Enhanced monitoring	**Additions to the basic monitoring program**		
	—	Well logs	—
	—	—	Wellhead pressure
	CO_2-flux monitoring	Continuous CO_2-flux monitoring	CO_2-flux monitoring
	Gravity survey		
	Electromagnetic survey		
	Pressure and water quality above the storage formation		

Table 3.
Monitoring program for geologic storage of CO_2 (modified after [51]).

Benson et al. [52] provided examples of basic and enhanced programs that could be deployed for geologic storage of CO_2. They include preoperational, operational and closure monitoring program and could be used over the lifetime of a geologic storage project. Their application in practice will enable the implementation of the CO_2 injection project and increase security and reduce the risk of migration of injected gas, thus protecting the environment (**Table 3**).

The choice of monitoring technology should be based on best practice available at the time of the design.

The parameters to be monitored are identified so as to fulfil the purposes of monitoring. However, the monitoring plan should in any case include continuous or intermittent monitoring of (1) fugitive emissions of CO_2 at the injection facility; (2) CO_2 volumetric flow at injection wellheads; (3) CO_2 pressure and temperature at injection wellheads (to determine mass flow); (4) chemical analysis of the injected material and (5) reservoir temperature and pressure (to determine the CO_2 phase behaviour and state).

The monitoring plan should be updated if new CO_2 sources, pathways and flux rates or observed significant deviations from previous assessments are identified.

Post-closure monitoring is based on the information collected and modelled during the implementation of the monitoring plan.

10. Conclusions

Increment of greenhouse gases in the atmosphere is a direct consequence of industrial development. It manifests itself in rise of the average earth temperature being responsible for a series of unfavourable climate changes. CCS can help in mitigating climate changes through a distinctive huge sequestration capacity, which ensures global utilisation. Technology applicability and safety have been testing by several large- and small-scale demonstration projects currently under way.

Switching CCS technology from demonstration to commercial deployment depends on CO_2 market price. Although current value is not encouraging, more stringent emission reduction strategy (80–95% by 2050) will lead to commercial applications. However, besides emission reduction initiatives, there are many projects connected to EOR activities. Viability of such projects is strongly dependent on the oil price.

Since geological storage permanence is enabled by natural and engineered barriers functionality, there is a certain risk of migration of CO_2 from the storage formation. The potential leakage risk increases during injection phase, and with time, it decreases due to activation of different trapping mechanisms. Therefore, structural/stratigraphic trapping represents the most important CO_2 storage mechanism in the first storage period. The other mechanisms take over with storage life progressively. Mineral tapping of CO_2 is the safest mechanism, as CO_2 reacts with the reservoir rock minerals and remains permanently trapped.

Well-selected, designed and managed geological storage sites pose the risks comparable to those associated with current hydrocarbon recovery activities. Such risks, determined by leakage rates of less than 1% over thousands of years, are well below levels that could endanger public safety or environment. Nevertheless, for all CCS projects, a comprehensive monitoring, including baseline, operational and post-closure state, is mandatory.

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