POLITECNICO DI TORINO

Petroleum and Mining Engineering

Master Thesis in Petroleum Engineering

Assessment and Challenges of CO_2 Injection into Depleted Reservoirs and Feedbacks to The Conversion of an Existing Offshore Platform

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Abstract

Re-using the depleted reservoirs for CO_2 storage offers advantages over saline aquifers, as the geological characteristics required for CO_2 storage have been pre-determined with high accuracy throughout the reservoir production life, plus a proof of secure containment. Additionally, re-using the production facilities and offshore platforms for the injection of CO_2 would be an economical and environmental winning fact, which is the case in this study.

This study, based on intensive bibliographic research, gives support to the MISE project regarding the challenges and concerns of CO_2 storage in depleted oil and gas reservoirs and the selection of the optimum solution for converting the offshore platform GREEN1 in the Adriatic Sea to be re-used instead of decommissioning. It also highlights the interactions between the reservoir parameters and the design of surface facilities. Thus, the design of all the upstream components, i.e., transportation pipeline diameter, compression capacity, and maximum allowable pressure is mainly based on the rock and fluid interactions in the reservoir porous media. Nevertheless, storage capacity has a vital role in the candidate sites screening process, accompanied by an economic feasibility study. From here, CO_2 storage capacity of 'Porto Corsini Mare' reservoir , as a candidate site for GREEN1, is estimated based on returning the depleted reservoir to its initial pressure before production.

Furthermore, a methodology for comparing and selecting the suitable reservoirs for CO_2 geo-storage is introduced, for the purpose of identifying the optimum storage site for GREEN1 platform. This screening criterion is divided into three main categories: storage capacity, injectivity, and containment, in the shape of logic flow charts with the relevant parameters to each category, in order to help analysts and decision makers identify and compare candidate sites for CO_2 storage, so that they are easily able to exclude the unsuitable reservoirs and proceed with the right candidates for further economic and risk assessment studies.

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Glossary

API	American Petroleum Institute
ASU	Air Separation Unit
BHP	Bottom Hole Pressure
CAT	Cap And Trade
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture for Utilization and Storage
CO_2	Carbon Dioxide
CSEGR	Carbon Storage Enhanced Gas Recovery
CSLF	Carbon Storage Leadership Forum
DAC	Direct Air Capturing
DGISSEG	Direzione Generale per le Infrastrutture e la Sicurezza dei Sistemi Energetici e Geominerari
EGR	Enhanced Gas Recovery
EOR	Enhanced Oil Recovery
ETS	Emission Trading System
FCM	First Contact Miscibility
FIT	Formation Integrity Test
GHG	Green House Gases
GOIP	Gas Originally In Place
HSE	Health, Safety & Environment
IEA	International Energy Agency
IEAGHG	International Energy Agency for Green House Gases
IPCC	Intergovernmental Panel on Climate Change
MCM	Multiple Contact Miscibility
MISE	Ministero dello Sviluppo Economico
MMP	Minimum Miscibility Pressure
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
OOIP	Oil Originally In Place
OSPAR	Oil Spill Prevention, Administration and Response
TD	Total Depth
WHP	Well Head Pressure
WHT	Well Head Temperature

Introduction

Greenhouse gases (GHG) released into the atmosphere by anthropogenic activities have raised warnings of global warming and climate change in the near future. Carbon Capture, Utilization and Storage (CCUS) recently became a major plan as a mitigation measure that prevents large amounts of carbon dioxide, from emission sources such as energy intensive industries and power plants, to be released into the atmosphere. CO_2 storage gained its importance after the breakthrough of carbon capturing techniques for limiting GHG emissions, and transmission to renewable and environment friendly energy resources. Nevertheless, Emission trading (ETS), also known as cap and trade (CAT), for carbon dioxide and other greenhouse gases (GHG) created a form of carbon pricing and motivated the energy companies for further investment in CO_2 geo-storage. ETS is an approach to face climate change by creating a market with limited allowances for emissions, that can lower competitiveness of fossil fuels and accelerate investments into low carbon sources of energy.

This study is a part of the project of 'Ministero dello Sviluppo Economico, Direzione Generale per le Infrastrutture e la Sicurezza dei Sistemi Energetici e Geominerari (MISE, DGISSEG)' to find the optimum solution for converting an offshore platform in the Adriatic Sea, at the end of its production life, to one of the following three options; Option 1: production of photovoltaic energy and production of desalinated water; Option 2: re-using the platform to re-inject CH_4-H_2 mixture into the wells for temporary storage; Option 3: re-using the platform to re-inject CO_2 into the wells for storage. The chosen offshore platform will be named 'GREEN1' for the purpose of this pilot study. It was also decided to locate the CO_2 capturing plant near the northern Adriatic Sea area, where the largest number of Italian platforms are present and, above all, where almost all the platforms that will be decommissioned in the next few years are located.

The main objective of this study is to evaluate and identify the technical capabilities, challenges, and storage capacity for the purpose of re-using the platform GREEN1 for CO_2 geo-storage and, in addition, to discuss all the issues related to the injectivity of CO_2 through the existing wells, the containment and seal ability of the reservoir for permanent trapping, and behavior of CO_2 within the reservoir pores. Furthermore, a deep investigation in the technical suitability of the assigned reservoir for CO_2 storage and the main challenges for implementation regarding both the depleted reservoir nature and offshore environment. Nonetheless, to investigate and develop reservoir screening criteria for underground storage of CO_2 that can be used for the primary selection process for other future CO_2 geo-storage projects.

GREEN1 is one of 99 existing offshore platforms, represents most of the Italian platforms in the Adriatic Sea. Its location is around 20 km far from shoreline. And, as a case study, it is considered to be the production platform that was used to produce natural gas from 'Porto Corsini Mare' field through 4 wells in the period (2001-2014) with a total cumulative gas production 485 MM Sm^3 out of Gas Originally In Place (GOIP) 600 MM Sm^3, and a recovery factor 80%. The initial reservoir pressure was 145 bar, while the current reservoir pressure after abandonment is 79 bar, reservoir temperature is 45 °C, with an average well depth 2000 m SSL.

Scope of Work

The study is focused on the geo-storage of CO_2 in depleted oil and gas reservoirs, and the identification of screening and selection criteria for the suitable candidate storage sites based on reservoir storage capacity, injectivity, and capability of CO_2 plume containment. Moreover, the main challenges during and after the storage process are analyzed and correlated with the assessment of the offshore platform GREEN1 design, by considering the reservoir 'Porto Corsini Mare' as a case study for the purpose of re-using it for CCS project.

The study is presented in the following sequence:

- **Literature review:** a brief introduction about the development of carbon capturing technologies and CO_2 injection as an enhanced oil recovery method (EOR), and CO_2 injection for permanent underground storage in saline aquifers and depleted oil and gas reservoirs, with a short presentation about storage site safety considerations and a qualitative risk and hazard identification procedures.
- **CO_2 properties:** a presentation of the physical and chemical properties of carbon dioxide that have an influence in the storage process. Starting with the phase diagram and the impact of pressure and temperature on CO_2 density and viscosity in each physical state, reaching to how its solubility in water is affected by the salinity, and the miscibility conditions of CO_2 in oil. Then CO_2 solubility in reservoir connate water and hydrate formation potential in pipelines and in porous media.
- **CO_2 behavior during transportation and injection:** this chapter is divided into two main parts; The first part is an explanation of the main factors affecting CO_2 flow behavior in porous media, i.e., rock wettability, fluid saturation, reservoir permeability, capillary pressure, and CO_2 diffusion in reservoir fluids. While the second part represents the flow in pipelines, showing the effect of pressure, temperature, and ambient conditions during the transportation of CO_2 from the carbon capturing source to the bottom of the injection well, and the considerations related to distance and phase behavior.
- **Challenges in offshore depleted reservoirs:** in this part, the potential challenges of CO_2 storage in depleted reservoirs are addressed with a focus on the reservoir depletion status that might experience a change in in-situ stress field causing a decrease in the fracture pressure limit, and the possibility of precipitation and migration of chemical or organic scales in the reservoir causing pore plugging and reducing injectivity. Also, the presence of residual gas, in case of depleted gas reservoir, might have a negative impact on the CO_2 injectivity. However, at the same time, the CO_2 storage can be exploited as enhanced gas recovery method (EGR) for depleted gas reservoirs. The presence of impurities in the injection stream is also discussed in this part showing how the phase diagram of CO_2 is affected by the percentage of impurities. Additionally, a deep investigation in the offshore monitoring challenges related to technical and logistic issues.
- **Identification of candidate sites:** this part is a major objective of the study, it is divided into five sections; 1) the possible techniques of calculating storage capacity, CO_2 trapping mechanisms, and the uncertainties related to capacity estimation. 2) the factors affecting reservoir injectivity that should be considered during reservoir selection for storage. 3) the ability of storage site to contain

the injected CO_2 and prevent it from any potential leaks. Additionally, the storage capacity of 'Porto Corsini Mare' field is calculated as an example of a candidate storage site.

- **Site screening and selection:** 1) discussing the technical screening criteria for defining the suitability of a reservoir for permanent CO_2 underground storage, and introducing a logic flow chart for primary selection process based on storage capacity, injectivity, and containment. 2) a further ranking and selection of the suitable candidate sites according to technical, nontechnical, and regulatory requirements.

1. Literature Review

CO_2 capturing has been used since the 1920s for separating CO_2 present in natural gas reservoirs from the saleable natural gas. In the early 1970s, some of the captured CO_2 from the gas processing facility in Texas USA, was transported to a nearby oil field and injected to boost oil recovery. This process known as Enhanced Oil Recovery (EOR) has been proven very successful, and millions of tons of CO_2 were captured and injected back underground every year. EOR gave the CO_2 an economic value and used it again to produce more oil. And eventually, when all the oil has been produced, the CO_2 can be permanently stored in the depleted oil reservoir preventing that CO_2 from being released to the atmosphere and contributing to the greenhouse effect and global warming.

1.1. CO_2 Capturing

CO_2 emissions from the power sector are mainly caused by fossil fuel firing or combined cycle gas turbine (CCGT) power plants. Emissions depend on the content of the fuel, the higher the carbon content, the higher the CO_2 emissions. Natural gas consists mainly of CH_4 and is characterized by almost half the emissions of coal with almost double LHV. The composition of the fuel is the reason behind this fact, as there are four hydrogen atoms for every carbon atom in the methane molecule. Furthermore, other modern power generation technologies, such as nuclear power, renewable energy sources, and green hydrogen, are less prone to emissions. The use of fossil fuels in power generation will continue until it is replaced by alternative technologies with zero emissions. *(Madejski et al., 2022)* Until these technologies are replaced, CO_2 capturing is crucial to reduce GHG and protect the environment. *Figure 1.1* represents the typical process of CCS system starting from the use of fossil fuels or biomass material in the generation of electricity and industrial products followed by the carbon capture process by either post-combustion or pre-combustion method, and then transporting it to the storage site. The capturing techniques are summarized in *Figure 1.2*, showing both chemical and physical separation methods, besides, both have different sorption mechanisms.*(Rubin et al., 2012)*

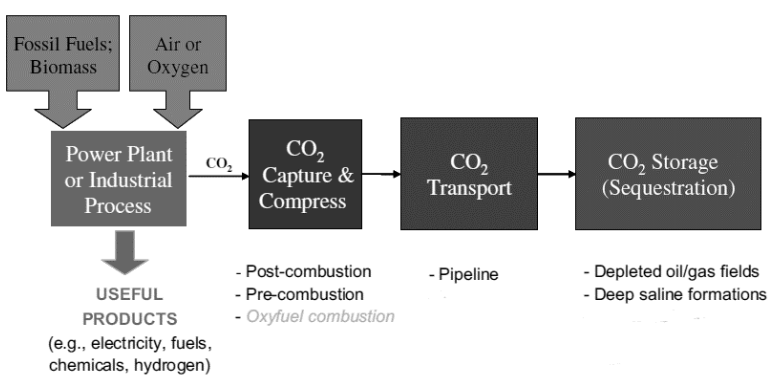


Figure 1.1 Typical CCS system, consisting of CO_2 capture, transport and storage.(Rubin et al., 2012)

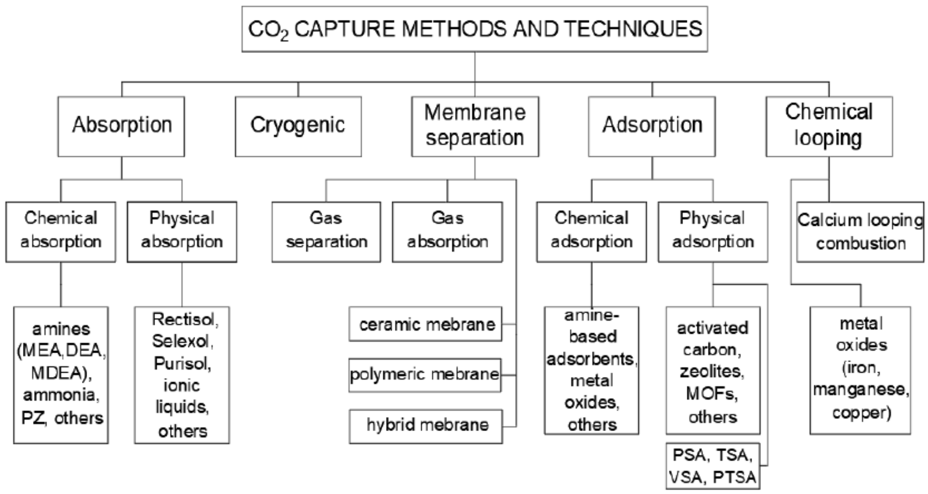


Figure 1.2 Methods and techniques of CO2 capture.(Madejski et al., 2022)

1.1.1. Post-Combustion

The post -combustion capture system is based on extraction Co2 from flue gases produced after burning fossil fuels or biomass. Nowadays, most of world's electricity is generated by these combustion-based power plants. To minimize the emissions, in coal fired power plants, pulverized coal (PC) is mixed with air and burned in a furnace to boil water for the purpose of generating steam that drives the turbine generators. The hot flue gases leaving the boiler contain mainly nitrogen, from the air, and small amounts of water vapor and CO_2. There are also other products produced from the impurities in the coal, like sulfur dioxide, nitrogen oxides, and fly ashes. These pollutants must be captured and removed according to applicable emission standards before releasing to atmosphere. Furthermore, removal of additional pollutants such as SO_2 is often required to provide gas stream that is sufficiently clean for subsequent CO_2 capture.

Currently, an organic solvent, i.e., Monoethanolamine (MEA) is the most effective method to capture CO_2 from the flue gases produced from PC power plant. In an absorber unit, the flue gas is washed with amine solution, as shown in *Figure 1.3*. The solvent, with CO_2, is then pumped to a stripper, where it is heated by steam vapor in order to release the CO_2. The resulting stream of concentrated CO_2 is then transported to the storage location, and the solvent is treated and recycled to the absorber. In a natural gas-fired boiler or natural gas combined cycle (NGCC) power plant, the same capture mechanism is used as in coal-fired plants. Although the concentration of CO_2 is less in flue gases in case of natural gas or NGCC, the efficiency of CO_2 removal is still high by using amine-based solvents due to the absence of impurities in the natural gas compared with coal, and therefore no additional cleaning process is required.

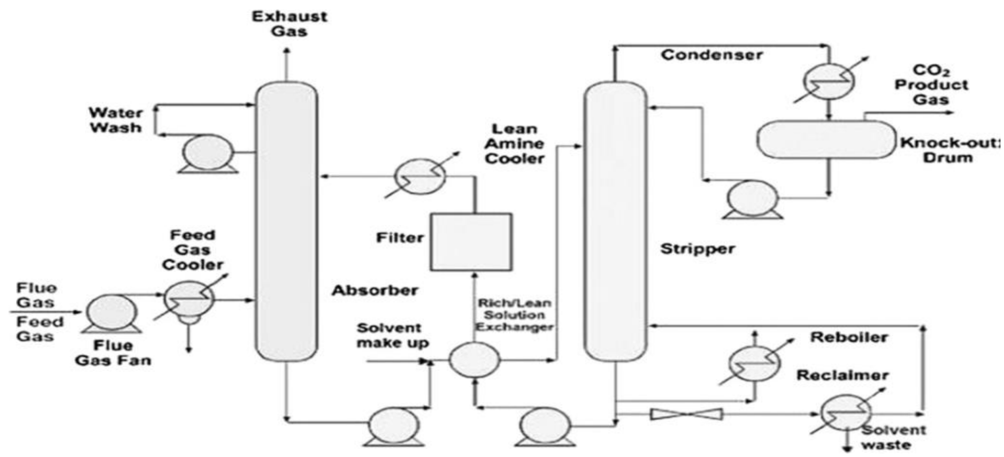


Figure 1.3 Flue gas and sorbent flows for an amine-based in a post-combustion CC system

1.1.2. Pre-Combustion

The removal of carbon before combustion requires converting it to amenable form for capturing. In coal power plants, a partial oxidation process is achieved by reacting coal with oxygen and steam at high pressure resulting in a synthesis fuel that consists mainly of carbon monoxide and hydrogen. This syn-gas is then burned for driving the combined cycle power plants, similar to NGCC described before, while this method is called integrated gasification combined cycle (IGCC). After removing the impurities from the syn-gas, carbon monoxide is converted to CO_2 through a shift reactor with steam (H_2O) that, in turn, produces hydrogen and CO_2. Hydrogen is burned for a clean power generation, while CO_2 is captured by a widely used chemical sorbent called Selexol, as in *Figure 1.4*, to be compressed and transported to the storage site.

Although the IGCC process is more complicated and expensive than the traditional coal-fueled power plants, the separation and capturing of CO_2 is much easier and cheaper because of the high concentration of CO_2 in IGCC and high operating pressure. So, instead of a chemical rection with amine solvent to capture CO_2, in post-combustion process, only physical absorption is required for the capturing, followed by pressure reduction to release the CO_2 from the sorbent.

In natural gas powered plants, the pre-combustion can take place, as with coal plants, by a reforming process where the natural gas reacts with oxygen and steam to be converted to synthetic gas. Then, shift reactor followed by CO_2 separation and the same procedures of IGCC.

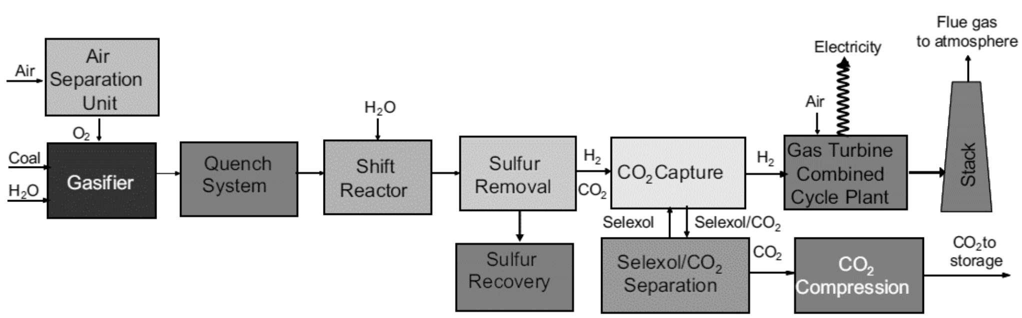


Figure 1.4 An integrated gasification combined cycle (IGCC) coal power plant with pre-combustion CO_2 capture.(Rubin et al., 2012)

1.1.3. Oxy-Combustion

As an alternative to post-combustion, oxy-combustion was developed for the traditional coal-fueled power plants. In this process, pure oxygen is used instead of air for the combustion, represented in Figure 1.5. The use of oxygen reduces the amount of nitrogen N_2 produced in the flue gas. Therefore, the flue gas only consists of CO_2 and water vapor, after removing fly ashes. The water vapor can be easily removed by cooling down, resulting in an almost pure CO_2 gas stream. Additional purification might be required to remove all minimal impurities like SO_2, N_2, and nitrogen oxides before transporting the gas to the storage site.

In oxy-combustion systems, the cost of carbon capturing is very low compared to the used of amine solvents or Selexol. However, the need of air separation unit (ASU) for separating oxygen from air is quite expensive, beside the additional purification cost for the extra impurities. Theoretically, oxyfuel systems can capture all the produced CO2, but because of the need to additional purification reduces the efficiency of the current systems to 90 percent.*(Rubin et al., 2012)*

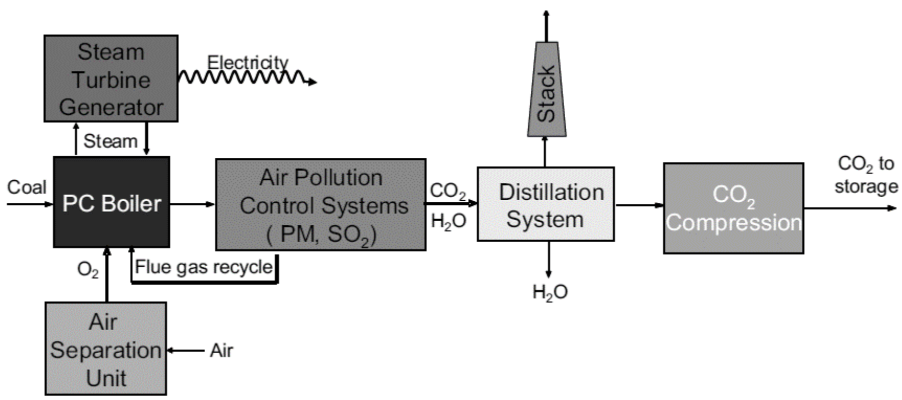


Figure 1.5 A coal-fired power plant using oxy-combustion technology.

1.1.4. Direct Air Capturing

The technology of direct air capturing (DAC) is developed for capturing carbon dioxide from the atmospheric air; as trees and plants do, but they are not capable to keep up with the increasing anthropogenic emissions nowadays. DAC is still practically not feasible process, as the required energy is to be minimized and carbon capture efficiency to be maximized. Many studies are working on improving the active material that captures CO_2 to achieve reasonable performance. The DAC systems can be categorized as high temperature aqueous solution and low temperature solid sorbent. Moreover, there are also other uncommon DAC techniques like electrochemical capture, ion exchange resin sheets, and many additional trials for reducing the energy consumption during CO_2 capturing from ambient air.

The HT aqueous solution mechanism is based on binging the ambient air, by a fan or natural air flow, in contact with sprayed NaOH (sodium hydroxide) or KOH (potassium hydroxide) that acts as a solvent in the absorption process, where the CO_2 reacts with it to produce Na_2CO_3 or K_2CO_3 in the ambient pressure and temperature. Then the product solution is transported to the cycle of regenerating the solvent (NaOH or KOH) and capturing CO_2, where the required temperature for the regeneration process is around 900 °C. While the LT solid sorbent system mechanism is allowing air to flow through an adsorption filter (mostly amines) that selectively captures CO_2 till it is fully saturated. Then the air inlet valve is closed, the remaining air is vented out, and the filter is heated up for releasing the captured CO_2 and regenerating the sorbent, as shown in *Figure 1.6.(Elfving et al., 2017; Fasihi et al., 2019)*

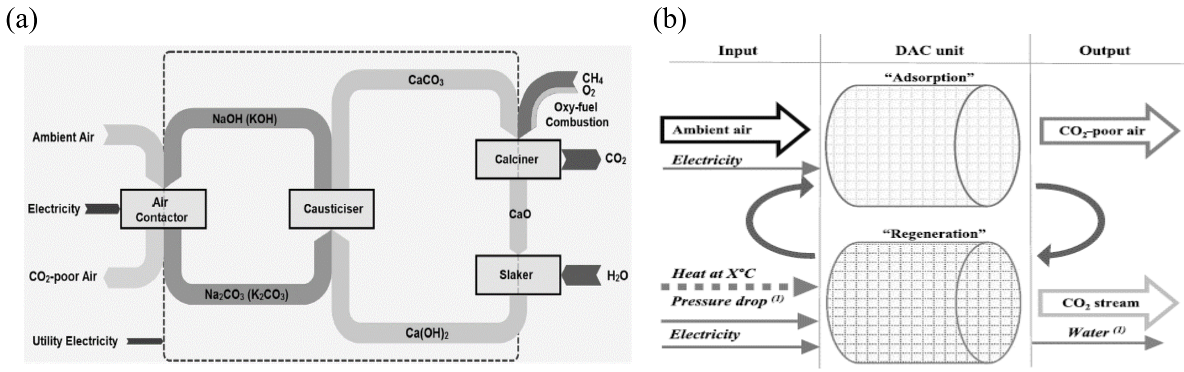


Figure 1.6 (a) HT aqueous solution DAC system, (b) LT solid sorbent DAC system.(Fasihi et al., 2019)

1.2. CO_2 for Enhanced Oil Recovery

Up to 21% of the oil originally in place (OOIP) is commonly produced by primary production, i.e., reservoir natural energy, plus additional 10% to 20% produced by secondary methods, i.e., water injection, leaving around 70% of OOIP remaining hydrocarbon underground.*(Bondor, 1992)* A big portion of the remaining oil can be produced by tertiary recovery (enhanced oil recovery EOR). There are many known EOR methods like polymer flooding, surfactant injection, in-situ combustion, steam injection (huff and buff), and CO_2 injection. CO_2 has a privilege over the other flue gases or natural gas for EOR which is its miscibility in oil at relatively lower pressure values, 100-150 bar. The heavier the crude oil (low °API), the higher the minimum miscibility pressure (MMP), as presented in *Table 1.1*, which means that the pressure of the injected CO_2 should be higher or at least equal to this MMP value.

Table 1.1 CO_2 miscibility conditions in crude oil.(Shaw & Bachu, 2002)

Oil Gravity (°API)	MMP (psia)	Temperature (°F)	Additional Pressure (psia)
< 27	4000	120	None
27-30	3000	120-150	200
> 30	1200	150-200	350
		200-250	500

CO_2 injection for the purpose of enhancing the oil recovery is based on reducing the oil viscosity, improving its relative permeability, and reducing the residual oil after the gas miscibility in oil. In addition, the injected CO_2 increases the reservoir pressure and displace the oil towards the producing wells. When the conditions of miscibility are achieved , a miscibility zone is formed at the interface between the oil and the displacing gas (CO_2), as represented in Figure 1.7, where the interfacial tension becomes zero and the capillary forces are absent. Therefore, this new developed displacing bank of a mixture of oil and CO_2 , is rich in oil at the front and rich in CO_2 gas at the back and creates a multiple contact miscibility (MCM) displacement process.

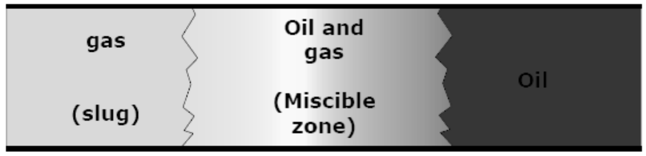


Figure 1.7 CO_2 miscible displacement illustration.

A first contact miscibility (FCM) process involves injection of a displacement fluid that forms only a single phase upon first contact when mixed with the oil in place, i.e., butane or crude oil. If the process is used after injection of water, the injected solvent must first displace the water phase to contact the residual oil and then the oil as a single phase mixture. A FCM process consists of injecting a relatively small primary slug, that is miscible with the crude oil at first contact, followed by a large secondary cheap slug to displace the developed oil mixture. While, in the MCM the condition of miscibility is generated through in-situ composition alteration of both residual oil in place and injected solvent, resulting from mass transfer between the fluids to the point that they become miscible as the injected solvent moves through the reservoir.*(Perera et al., 2016)*

Miscibility between CO_2 and oil is developed according to a sort of MCM through both condensing and vaporizing mechanism. CO_2 condenses into the oil making it lighter and driving the lighter components out of it. These lighter components of the oil vaporize into the CO_2 phase making it denser and more easily soluble into the oil. Mass transfer continues until the resulting two mixtures of CO_2-enriched oil and oil-enriched CO_2 become indistinguishable and no interface between the two fluids.

1.3. CO_2 Storage

CO_2 storage have been tested and verified at many sites all over the world, including saline aquifers and depleted oil and gas reservoirs. Re-using depleted reservoirs for carbon storage has several advantages due to the availability of geological information and reservoir model. However, the presence of many wells intersecting the reservoir increases the risk of CO_2 leakage back to surface or to other formations. There are many successful cases of CCUS all over the world, and yet more to come following the mitigation plan against climate change due to GHG release into atmosphere.

K12B offshore platform in the North Sea represents a not only a good CCS process, but also a successful enhanced gas recovery (CSEGR). It is the first site in the world in which CO_2 is re-injected into the same reservoir that produced it, where about (0.03-0.05) ton of natural gas are extracted per each ton of CO_2 injected.*(Liu et al., 2021)* Also, *The Petra Nova CCS,* in the U.S., is designed to capture approximately 90% of the carbon dioxide and sequester approximately 1.4 million metric tons annually from a coal fired power plant and then transport it through 132 km pipeline to be injected in an oil reservoir for EOR purpose. Furthermore, *Sleipner* and *Snohvit,* in Norway are considered the most successful CCS in saline aquifers projects in Europe. In *Snohvit*, CO_2 is injected into a sandstone saline aquifer beneath the producing Snohvit gas reservoir. While in *Sleipner*, 1 Mt of CO_2 per year, since 1996, into a shallow sandstone saline aquifer.*(A. Chadwick & Eiken, 2012)*

1.4. Safety and Risks in Storage Sites

Slowly leaks of CO_2 from a reservoir under the ocean would not generally have an immediate threat to humans. In the open water, released CO_2 is partially dissolved in the water column, and the remaining CO_2 that escapes to the atmosphere is mixed with air and diluted. For people on offshore installations, the situation may be different if they are directly above the leak. However, studies of natural analogs indicate that CO_2 leakage from the subsurface poses little risk to humans. A prerequisite for it to cause suffocation by accumulation in topographic depressions, which is not the case in offshore environment. Furthermore, wind would cause quick mixing and dilution in the atmosphere. While spills from offshore pipelines, wells, and reservoirs could affect a larger area due to dissolution and acidification of the surrounding seawater.

The possibility of a blow-out (sudden release of CO_2 from a subsurface storage site) is practically zero. Preventing this blow-out can be achieved by full investigations of the storage sites and caprocks prior to storage. They must include 3D seismic surveys, drilling, reservoir and geomechanical simulations, and a robust monitoring program. *(R. A. Chadwick & British Geological Survey, 2008)*

Table 1.2 Geomechanics-related risk mechanisms for loss of bounding seal integrity.(Hawkes et al., 2005)

Risk factors	**Mechanisms**	**Assessment and mitigation methods**	**Key parameters**
1. Faults reactivation within or bounding the reservoir	Local pressure increase in the fault plane during injection -> effective normal stress reduction -> reduction of fault shear strength	Geochemical analyses to determine maximum safe pressure. Injection of sweet spots into the reservoir. Selection of injection wells distant from faults.	- in situ stress magnitudes - pore pressure in fault plane - orientation of fault plane - fault friction angle
1bis. Faults reactivation within or bounding the reservoir	Pervasive pressure changes throughout the reservoir -> change in in-situ stress magnitude -> higher risk of fault reactivation when reservoir pressure is depleted	Geochemical analyses to determine if stresses at minimum reservoir pressure were capable of causing slip. Review records for indication of seismicity during primary and secondary recovery operations.	- present day stress regime - orientation and strength properties of fault cutting across or bounding the reservoir - depletion response of the reservoir - minimum pressure experienced during depletion
2. Fault reactivation in overburden or caprock	Pressure depletion-> reservoir compaction -> overburden or caprock subsidence. Shear stresses development in overburden in regions overlying lateral limits of reservoir	Geo-mechanical analyses to assess if subsidence, induced shear stresses at minimum reservoir pressure were capable of reactivating faults. Historical data review for indication of seismicity during primary and secondary recovery operations.	- reservoir thickness - pressure changes - uniaxial compaction coefficient - reservoir depth
3. Induced shear failure	Expansion and contraction of reservoir during injection and production-> shear stresses at reservoir caprock boundary. Large horizontal compressive stress at apex of structure for domed or anticlinal reservoirs	Geochemical analyses to determine maximum safe delta pressure (exceeded during production? To be exceeded during injection? Caution to reservoir HP/HT.	- reservoir compressibility - stiff caprock - pressure changes - low strength caprock - depth - domed and anticlinal reservoir - temperature changes (considered only when operations involve injecting fluids from surface)
4. Out of zone hydraulic fracture: prior to CO2 injection	*Reservoir*: Fracture treatments, high pressure squeezes, waterflood-induced fracturing. *Overburden/caprock*: fracturing during cementing or workover.	Operational history. Review cementing and workover reports (records of significant losses or high ECDs). Microfrac and minifrac tests.	
4bis. Out of zone hydraulic fracture: during CO2 injection	Injection above fracturing pressure -> fractures within the reservoir -> caprock -> overburden/underburden	Avoid fracturing. Identification of safe upper pressure limit and maintain of a reasonable safety margin. Injection of sweet spots into reservoir. Selection of high permeability storage reservoir to avoid fracturing.	- stiff reservoir formations - large thermal expansion coefficient - injection fluid temperatures (lower than in situ reservoir (temperature)

The leakage of CO_2 is considered the main risk in terms of probability of occurrence, magnitude, and impact. It can occur in several ways; CO_2 can migrate through the reservoir to areas where the caprock is absent or weak, then it can leak either through the upper or lower boundary seal. *(Ramírez et al., 2010)* There are several approaches to reduce the likelihood of geomechanically induced leakage that include the identification of safe upper limits on injection pressures, preferred locations for injection wells, reviewing historical records of reservoir pressures, temperatures, and stimulation treatments, and evaluating well integrity indicators for existing wells. *Figure 1.8*, shows an example of a potential risk of soil acidification due to the possibility of CO_2 leak up to surface soil through an existing fault. While *Figure 1.9*, shows the possible risk identification scenarios. In all cases, the most robust approach to quantitative risk assessment would involve coupled reservoir-geomechanical simulations. In this way, the site-specific aspects of each potential reservoir can be evaluated. *Table 1.2*, represents an example of the critical geomechanics related risk parameters affecting the CO_2 containment, and methods to assess and mitigate these risks.*(Hawkes et al., 2005)*

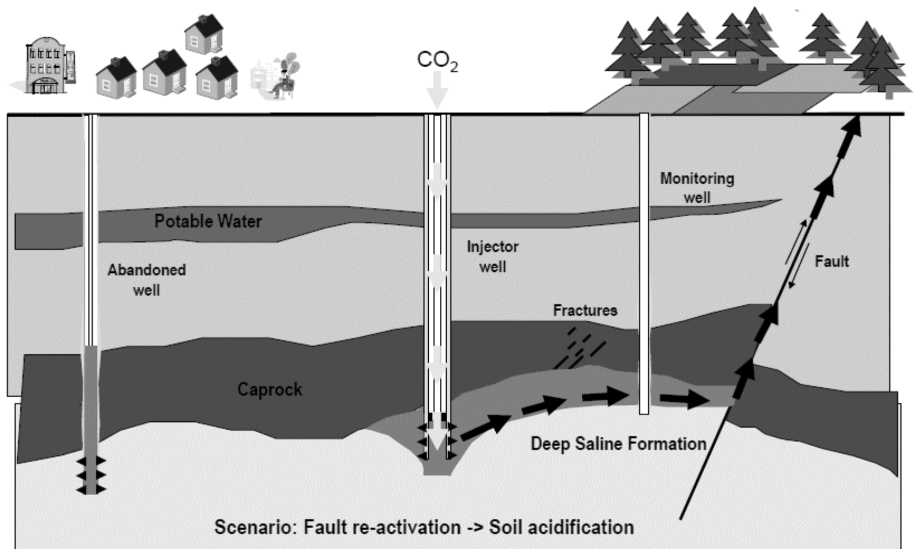


Figure 1.8 Example of risk analysis - CO_2 Containment Risk (Scenario: Fault re-activation -> Soil acidification).(Vivalda, 2021)

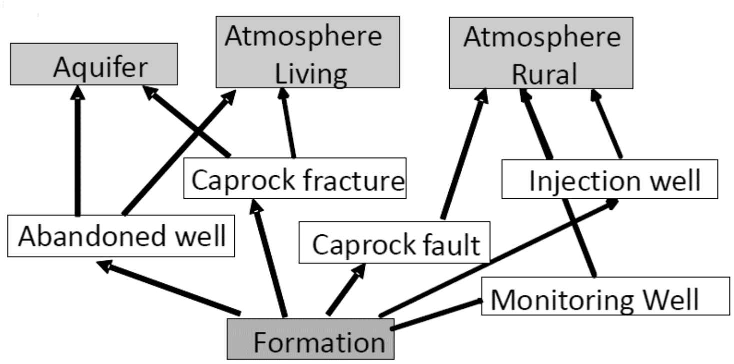


Figure 1.9 Risk pathway identification scenarios building.(Vivalda, 2021)

Two relatively consistent monitoring requirements have emerged from offshore storage regulation; The first is to demonstrate that a storage site is currently operating effectively and safely, and the second is to ensure that it will continue to do so in the future by providing information to support and calibrate predictions of future performance. These requirements can be divided into a set of necessary actions that fall into two main objectives of monitoring: containment and conformance assurance. A third criterion, contingency monitoring, may be required if the requirements for containment or conformance requirements are not met. *(Hannis et al., 2017)*

2. CO_2 Properties

CO_2 is a chemical compound including carbon and oxygen. It has natural presence in the atmosphere with a small quantity (370 ppmv). Nonetheless, it has a main role in the Earth's environment and in the life cycle of plants and animals, i.e., during photosynthesis process, plants assimilate CO_2 and release oxygen. The emission of CO_2 comes as a product of the combustion of organic substances fossil fuels, the fermentation of organic compounds, and the breathing of humans. CO_2 gas is colorless and denser than air.

2.1. Physical Properties of CO_2

The physical state of CO_2, as all fluids, varies with temperature and pressure as shown in the P-T diagram Figure 2.1. At low temperature, less than 56.4°C, CO_2 is in the solid phase when the pressure is below 5.1 bar. The solid phase will sublime directly into vapor phase below the triple point (5.1 bar and 56.4°C). At the temperature range between -56.4°C and 31.1°C, CO_2 can be turned from the vapor into liquid phase by increasing the pressure to the corresponding the saturation line. After the critical point (73.8 bar and 31.1°C), it is called a supercritical state, where CO_2 behaves as a gas. The density of the CO_2 at super critical state can be very large, even exceeding the liquid water density. Furthermore, the viscosity of CO_2 varies with phase behavior, as shown in *Figure 2.2.(Bachu, 2008; Metz et al., 2005)* The behavior of density and viscosity with pressure and temperature is a key factor in implementing CO_2 underground storage capacity and injectivity.

According to the laws of thermodynamics, heat is absorbed or released in each of the phase changes, solid to gas, solid to liquid, and liquid to gas. However, the phase change from the supercritical state to liquid or from supercritical to gas does not absorb or release thermal energy. which is useful for the design and implementation of CO_2 injection. Therefore, no need to handle the heat related to the liquid to gas phase change or vice versa.*(Bachu, 2008)*

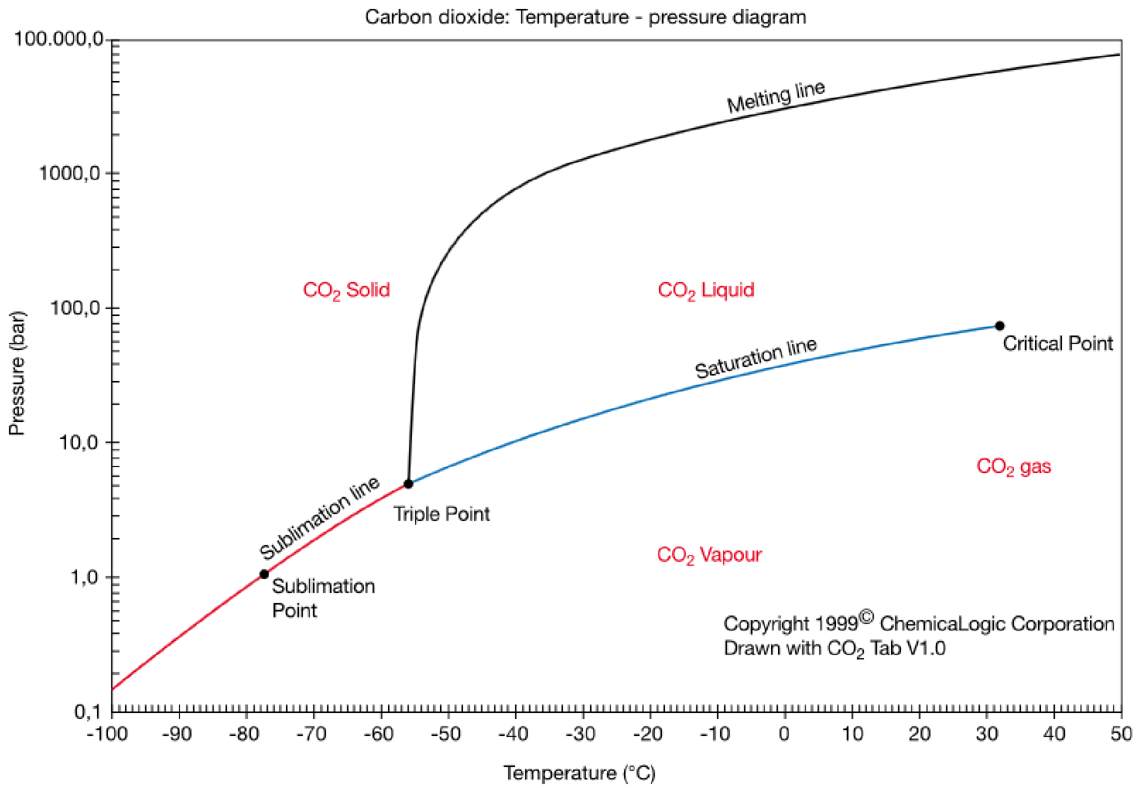


Figure 2.1 CO_2 pressure-temperature phase diagram. (Metz et al., 2005)

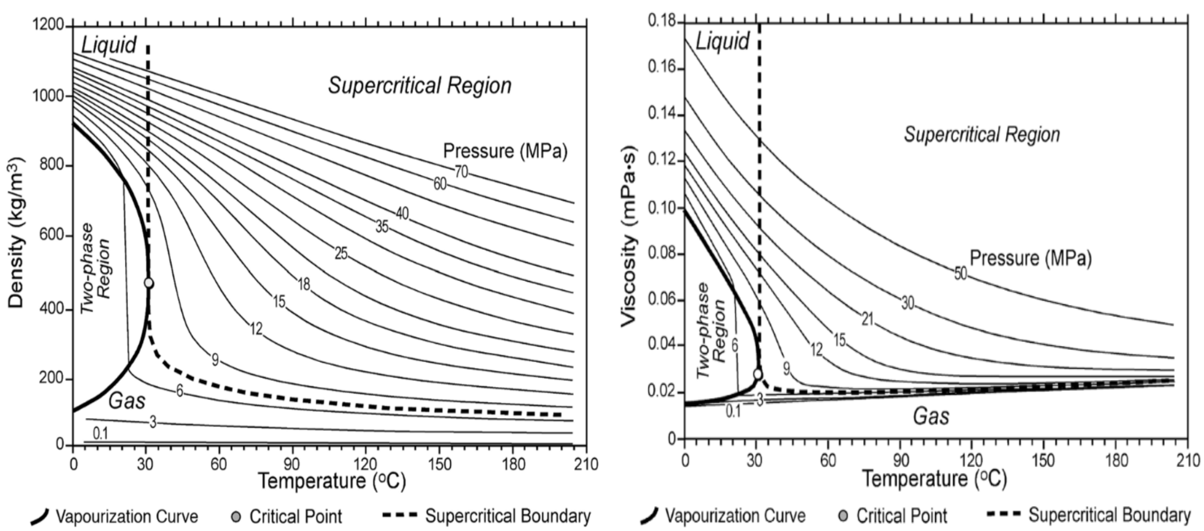


Figure 2.2 CO_2 density & viscosity as a function of temperature and pressure.(Bachu, 2008)

2.2.Solubility of CO_2

In aqueous solution CO_2 with water form carbonic acid, H_2CO_3. The solubility of CO_2 in water decreases with increasing temperature and increases with increasing pressure. Its solubility in water also decreases with increasing water salinity as represented in Figure 2.3, the effect of water salinity on

CO_2 solubility in it, that has a vital role in the solubility trapping potential of CO_2 in water bearing reservoirs, as mobile or connate water.

The dissolution of CO_2 in water, producing carbonic acid, causes a reduction of *p*H value of the solution down to (*p*H = 3). Several studies proved the pressure and temperature variation has a minor effect on changing the solution *p*H, *Figure 2.4.(Metz et al., 2005)* In underground storage, this acidic solution may react with the rock minerals, specially carbonate rocks, creating channels inside the porous media and enhancing the fluid injectivity in the reservoir rock.

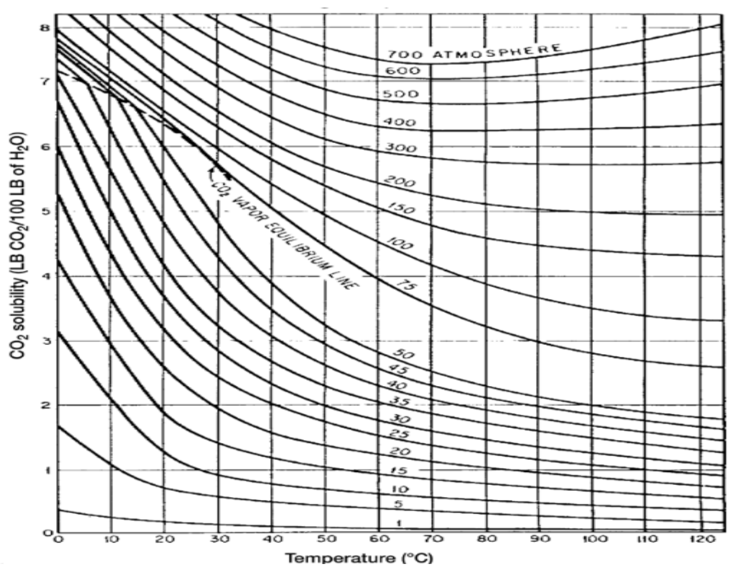


Figure 2.3 Solubility of CO_2 in water.(Metz et al., 2005)

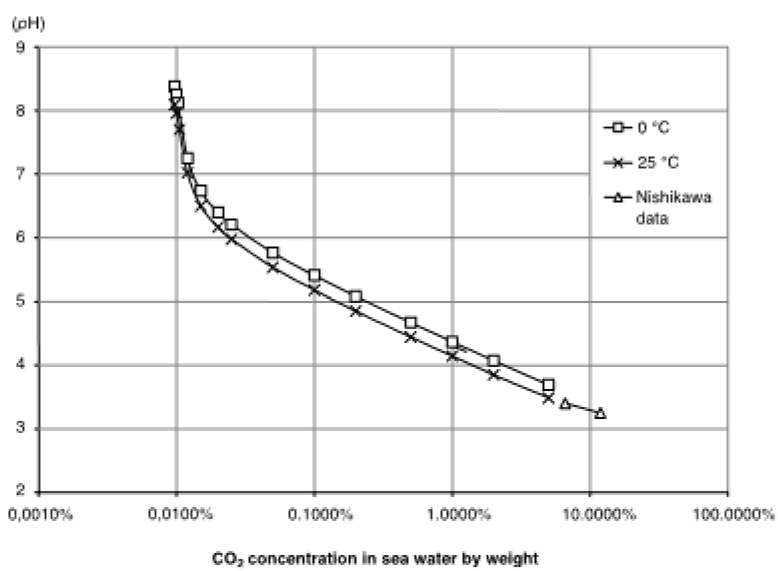


Figure 2.4 Effect of CO_2 concentration on the pH of sea water.(Metz et al., 2005)

2.3. Hydrate Formation

A hydrate is a crystalline icelike compound composed of water plus guest molecules. The host is formed from a tetrahedral hydrogen bonding network of water molecules, this network is open to create pores which are large enough to contain other small molecules. The guest molecules can be CH_4 and/or CO_2. The hydrates of CO_2 ($CO_2.nH_2O$) have much similar properties to methane hydrates ($CH_4.nH_2O$), but not identical. The formation of hydrates in a gas pipeline depends mainly on the pressure, temperature, and presence of water vapor in the gas stream. It is accelerated by a sudden pressure drop, due to flowing through a restriction or change in pipe diameter, this sudden pressure drop reduce the temperature (Joule-Thomson effect) causing the formation and accumulation of these icelike crystals leading to the plugging of the flowline.

CO_2 hydrates are very unlikely to occur in depleted reservoir porous media, as the Joule-Thomson cooling effect is very weak, even in reservoirs with high permeability up to 1.0 Darcy. While in low permeability reservoir the cooling effect due to gas expansion can be neglected.*(Oldenburg, 2007)*

3. CO_2 Behavior During Transportation and Injection

The design of the offshore platform GREEN1 that is 20 km far from the shoreline isn't only affected by the CO_2 flow mechanics through the pipes during transportation, but also affected by the behavior of CO_2 through the reservoir. In fact, the selection of the upstream facilities, i.e., compressors, heaters, or pipelines, for CO_2 geo-sequestration in mainly based on the downstream capabilities. All the involved reservoir parameters should be studied together to achieve the best model representing the optimum injection plan and the potential capacity, so that the selection of the most suitable candidate would be much easier.

3.1. CO_2 Behavior in Porous Media

Understanding CO_2 behavior in the bearing formation is a fundamental factor to get the right match with the design of all the upstream design parameter including the surface compression equipment, the capturing source capacity, and the degree of CO_2 purity. In this part, the rock and fluid properties in porous media and their mutual interactions are discussed, showing their influence on the process of CO_2 injection.

3.1.1. Wettability

Wettability, *Figure 3.1*, is the degree of tendency of a fluid to wet and adhere to the rock surface in a porous media within the presence of other immiscible fluids. It is a major property characterizing the flow and dispersion of liquids inside a reservoir. Like in hydrocarbon reservoirs, multiphase flow behavior during CO_2 injection is affected by the wetting state of the containing rock.

The capillary pressure and relative permeability curves are both directly dependent on the wettability state of the porous medium; Thus, the capillary sealing of the caprock, which is affected by caprock wettability state, is essential factor for efficient containment of the injected CO_2 in the bearing formation.*(Donaldson & Alam, 2008)*

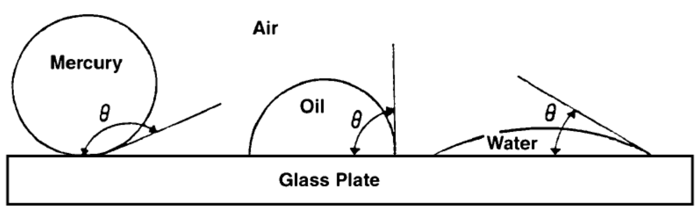


Figure 3.1 Representation of wettability (high tendency for the water to adhere to the glass plate while the mercury is representing a non-wetting fluid)

Several projects worldwide have applied CO_2 injection in depleted oil and gas reservoirs. Injection was either directly into the depleted reservoir (e.g., K12-B field in Netherlands), or into the water aquifer of the reservoir (e.g., Otway Basin in Australia and Salah field in Algeria). Regardless of the details of these projects, injection into depleted reservoirs that are saturated predominantly with brine water and/or residual gas requires a full understanding of the rock-fluid interactions in porous media i.e., relative permeability and capillary pressure, that are described later in this chapter. However, water wet reservoirs are still the preferred category for carbon storage projects due to the ease of CO_2 to flow and their high capillary sealing and containment for long term storage.*(Oldenburg & Doughty, 2011)*

3.1.2. Fluid Saturation

Saturation ($S_{w,o,or\ g}$) is the fraction or percentage of each fluid phase in the pore space. In a multiphase immiscible displacement system, there are two main processes, *Figure 3.2*, both are depending on the rock wettability and which fluid is displacing the other one. drainage process in which the non-wetting phase is displacing the wetting phase fluid, and the imbibition process is when the change in saturation is towards the increase of the wetting phase i.e., water flooding process in a water-wet formation. For CO_2 injection in saline aquifers, the case is always considered as drainage process, as the saturation of CO_2 (the non-wetting phase) is increasing.*(Ahmed, 2006)*

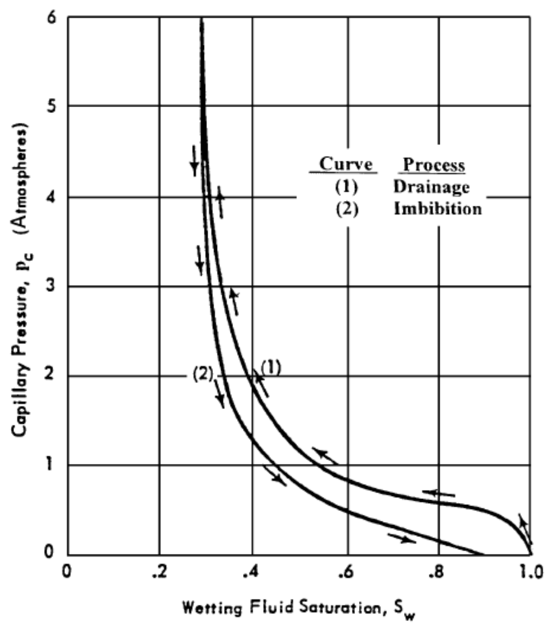


Figure 3.2 Drainage and Imbibition processes vs Capillary pressure.

The saturation of residual hydrocarbon in place (gas or oil) may affect the CO_2 injection process and reservoir storage capacity estimation. Since gases have higher compressibility and can be efficiently displaced by the injected CO_2, the residual gas saturation tends to give higher storage capacity of a geological porous structure compared to pores filled only with liquid phase (oil or water). However, it can have a contrary effect on the fluid flow performance and relative permeability during CO_2 injection due to the different physical and thermodynamic interactions of the new gas mixture. Later, in the next chapter, it is explained in more detail the effect of residual gas saturation on CO_2 storage.

3.1.3. Absolute and Relative Permeability

Permeability is a rock property describing the ease of fluids to flow through the rock interconnected pores. Absolute permeability, an intrinsic characteristic of a porous rock, is the permeability of porous rock 100% saturated with a single fluid or phase. It does not depend on fluids that flow into the rock, and it is only related to pore geometry of the rock itself. When more than one phase present in the reservoir rock, the resulting permeability to each phase is called effective permeability; It represents the conductivity of each phase at a specific saturation. The fluids within the pores interfere with each other so that the individual effective permeability to each phase, as well as their sum, is lower than the rock absolute permeability.*(Donaldson & Alam, 2008)*

Relative permeability (k_r) is the ratio of a fluid effective permeability ($k_{w,\ o,\ or\ g}$) to absolute permeability (k). The shape of relative permeability curve vs saturation is a function of the fluid distribution within the porous medium and the rock wettability. In accordance, CO_2 relative permeability curve, *Figure 3.3*, is changing with CO_2 and water phase saturation; In strongly water-wet reservoir the residual water saturation, at which gas is the only mobile phase through the porous medium, is 50% of the pore volume, while in CO_2-wet system it is 10% of the pore volume. This can affect the risk of CO_2 containment of the cap rock in presence of wettability alteration process.*(Al-Khdheeawi et al., 2017)*

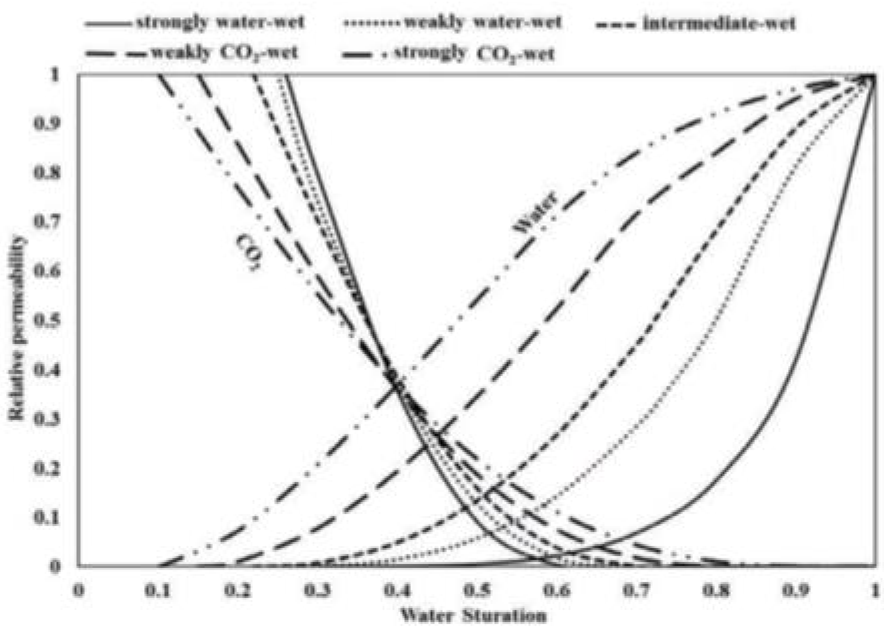


Figure 3.3 Relative permeability curves for the five tested water-CO_2 wettability conditions (Al-Khdheeawi et al., 2017)

Usually, the permeability of sedimentary rocks in the horizontal direction is higher than the vertical permeability, in the absence of vertical fractures or channels, due to the sedimentation environment that creates natural vertical layering. So, the fluid flow in the vertical direction is more restricted compared to the horizontal direction. However, in some CO_2 geo-storage cases, vertical permeability and vertical displacement performance have a primarily important matter because of the gravity segregation and buoyancy nature of the injected CO_2.

3.1.4. Interfacial Tension and Capillary pressure

When two or more immiscible fluids coexist in a pore space, they are separated by boundaries at which discontinuities in density and pressure exist. Interfacial forces act only at the boundaries between the phases and are tangential to the boundary. The Pressure difference existing at the separation surface between two immiscible fluids is called Capillary Pressure, Equation 3.13.1.*(Ahmed, 2006)*

$$P_c = P_{nw} - P_w \qquad 3.1$$

P_c = capillary pressure [bar]
P_{nw} = pressure of the nonwetting phase[bar]
P_w = pressure of the wetting phase[bar]

Displacing a fluid by another fluid in a porous media is either supported or opposed by the capillary effect. In other words, to keep a porous media partially saturated with non-wetting phase, in the presence of a wetting phase, it is mandatory to keep the pressure of the non-wetting phase greater than the wetting phase pressure. As observed in *Figure 3.4*, there is a pressure value (P_d), in a fully water saturated core sample, that is required to displace the non-wetting fluid with the wetting fluid (water). This minimum pressure (P_d) is also known as the minimum displacement pressure. *(Ahmed, 2006)*

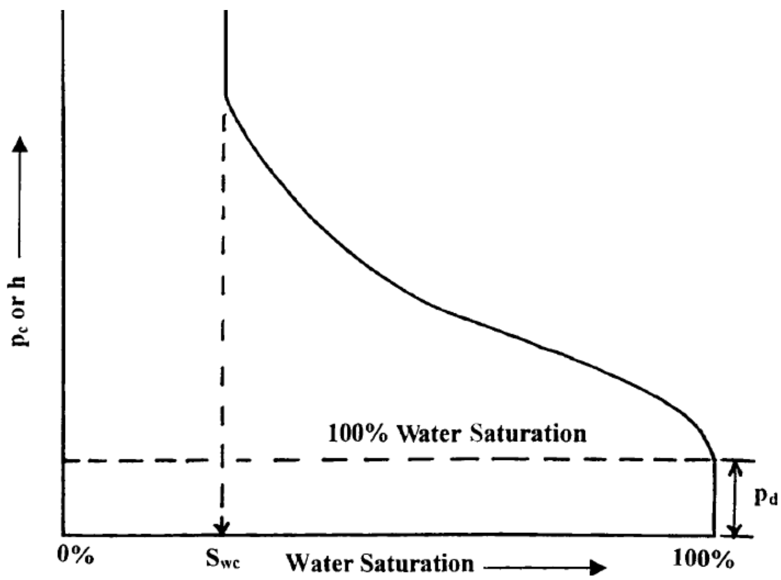


Figure 3.4 Capillary pressure curve (Ahmed, 2006)

3.1.5. CO_2 Diffusion in Reservoir

CO_2 geo-sequestration in saline aquifers occurs through different mechanisms. When CO_2 is injected into the aquifer, it migrates upward due to buoyancy forces to be trapped by a top impermeable cap rock, i.e., structure trapping. After CO_2 trapping at the top of the reservoir, it starts to diffuse into the underlying brine water, i.e., dissolution trapping. The CO_2 diffusion at the interface between the two phases causes an increase in the density of brine, which creates instability in the system and mass transfer process controlled by many factors, such as the pressure, temperature, and water salinity.*(Rezk* *et al., 2022)* However, in depleted reservoirs, partial dissolution of CO_2 in connate water might have a positive effect on increasing reservoir storage capacity, solubility trapping, depending on water salinity, that is a main trapping mechanism in this process.*(Jalil et al., 2012)*

CO_2 dispersion in gas bearing formation was also found to be affected by connate water salinity in gas reservoirs, as higher water salinity tends to decrease the dispersion coefficient of CO_2 in methane at some conditions. *(Abba et al., 2017; Liu et al., 2021)* Which promote the idea of exploiting CO_2 storage in enhanced gas recovery.

3.2. CO_2 Behavior in Pipes

Because of the criticality of CO_2 phase diagram having critical temperature close to the ambient conditions, T_c=31.1°C, its flow behavior is sensitive to the geographic location and the temperature of the surrounding environment through the seasons of the year. Also, the critical pressure of CO_2, P_c=73.8 bar, is in the range of most operational pressure values. CO_2 is normally transported in liquid or supercritical phases. Mostly, the supercritical state is used with pipelines and the liquid state is mainly used in batch transportation i.e., truck, train, or ship.*(Metz et al., 2005)*

In the following part, we are discussing the different flow performance of CO_2 in pipes during transportation from the source capturing plat to the permanent underground sequestration reservoir.

3.2.1. Land Pipeline

Transporting CO_2 on surface, from the carbon capturing plant to shoreline is considered relatively the least challenging process compared to wellbore injection or transportation through underwater line. The cost and complexity of such process is lower due to the ease of its design and maintainability. Technically, CO_2 can be transported in gas, supercritical, or subcooled liquid phase while, operationally in most of the EOR projects, supercritical state is adopted in CO_2 transportation. Although the subcooled liquid transportation has higher energy efficiency and lower transportation cost over long distances in cold climate areas or by thermally insulating the pipeline, in hot climates, periodic cooling to the CO_2 below its critical temperature, 31.1°C, can be non-economical.*(Boodlal et al., 2018)* While gaseous phase is avoided due to the gas phase low density, *Table 3.1*, as a result, a large pipe diameter with high pressure drop is required for the transportation process. *(Zhang et al., 2006)*

Table 3.1 Density and viscosity of CO_2 in gaseous, supercritical and liquid states.(Zhang et al., 2006)

Property	Gas	Supercritical	Liquid
Density (g/cm^3)	0.001	0.2–1.0	0.6–1.6
Viscosity (g/cm.s)	0.0001	0.001	0.01

Zhang et al., (2006) also suggested that, for distances more than 350 km, transporting CO_2 in a subcooled liquid phase will reduce the capital cost by 16%. In *Figure 3.5*, they simulated the variation of density along a CO_2 transportation pipeline, without change in elevation, with inlet pressure 150 bar at two different inlet temperatures, 20°C & 40°C representing subcooled liquid phase and supercritical phase respectively. It is observed that there is a gradual decrease in density in both phases. Nonetheless, the abrupt change in density is caused by reaching the saturation line where two liquid and gas phase coexist that requires a repressurizing process before reaching that line. For a constant mass flow rate, the decrease in density will also cause an increase in flow velocity which, in turn, increases the pressure drop through the pipe and possibly results in erosion and cavitation in the pipeline.

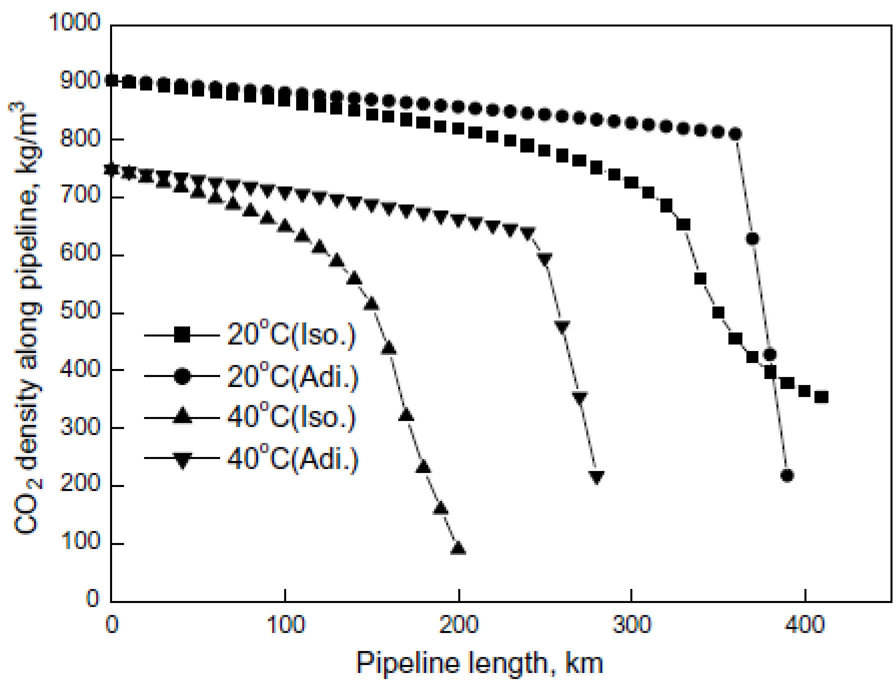


Figure 3.5 CO_2 density changes along pipeline at different inlet temperatures with isothermal & adiabatic conditions; pipe inlet pressure = 150 bar, inner pipe diameter = 0.29 m, CO_2 flow rate = 245 tons/h.(Zhang et al., 2006)

3.2.2. Underwater Pipeline

Underwater pipelines up to 1.4 m diameter and water depth up to 2200 m were successfully constructed in different environments.*(Metz et al., 2005)* The design and implementation of underwater transportation line is considered to be more challenging due to the variation of seawater temperature throughout the year, related to the geographical location, between 30°C in tropical areas and less than 0°C in deep water and cold climate areas, in addition to the pipe collapse potential in deep water depths. Both, capital cost and operational cost of such pipeline are related to the length and water depth, which are high cost compared to surface transportation.*(Boodlal et al., 2018)* Regarding the technical issues, like land pipeline, understanding the behavior of CO_2 phase diagram and heat transfer between the line and seawater is the key for a successful model and adequate site preparation.

3.2.3. Through Wellbore

In vertical transportation, not only the pressure changes abruptly with depth, but there is also a gradual increase in the ambient temperature caused by the geothermal gradient of the injection area. At the early injection stage while the pressure in the reservoir builds up, when the reservoir pressure is below the CO_2 saturation line, and CO_2 is injected in the liquid or supercritical phase, CO_2 will expand within the wellbore or in the vicinity of wellbore region in the reservoir. This behavior is accompanied by many flow-assurance issues. The sharp change in density affects the wellhead pressure control and the bottomhole pressure response. As mentioned before, the resultant high flow velocity can cause erosion and cavitation in the flowlines. *(Hoteit et al., 2019)*

CO_2 expansion is also associated with the Joule-Thomson effect, which might anticipate the formation of CO_2 hydrate or dry ice in the wellbore, and consequently reduce CO_2 injectivity. However, If Joule-Thomson cooling effect occurred extremely, inside the reservoir around wellbore, CO_2 injectivity and rock permeability can be altered by the freezing of connate water, and induced fracturing caused by thermal stresses. So, Understanding the flow behavior of CO_2 through the wellbore is crucial for optimum injection design and operational risk assessment.*(Oldenburg, 2007)*

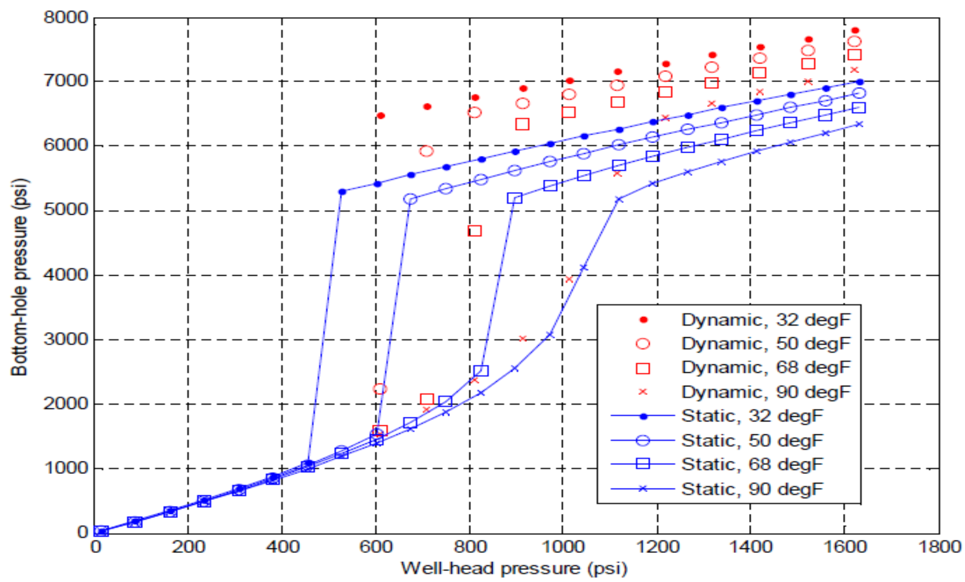


Figure 3.6 Bottomhole pressure (psi) as a function of wellhead pressure at 15,000 ft for 4 different injection temperatures. With injection rate of 10,000 tons CO_2 per year, a surface temperature of 59°F (constant down to 492 ft) increasing to 278 °F at TD. Static pressure was computed with temperature varying linearly between injection and downhole values. (Loizzo et al., 2010)

In practical applications, injection is controlled by regulating wellhead pressure in order to deliver an acceptable downhole pressure, with the desired flow rate, that must be maintained between reservoir pore pressure and fracture pressure to be able to achieve the injectivity of CO_2 without causing reservoir damage. Downhole pressure may abruptly change due to the phase transformation inside the wellbore from light to dense fluid, causing an increase in the fluid column weight. Plus, a change in fluid density and viscosity resulting in a different injectivity index has a big influence on the underground reservoir flow dynamics and injection rate. This behavior anticipates the risk of reservoir or cap rock fracturing and fluctuation in injection parameters. In *Figure 3.6*, a practical example that shows the effect of the injectivity gap and how a slight increase in WHP can cause a huge change in BHP at different temperatures computed at depth 15,000 ft (~ 4570 m). *(Loizzo et al., 2010)*

Based on CO_2 properties and according to its behavior during transportation and injection, The following points should be considered for the conversion of an offshore platform (GREEN1) for CO_2 geo-sequestration:

- *The transportation and injection of CO_2 in super critical phase is preferred due to its high density and low viscosity, thus, better injectivity.*
- *Expecting a sharp increase in WHP during the first days of injection, until the reservoir boundaries are reached. Then, due to slow reservoir pressure increase, the pressure build-up rate is much lower after reaching the boundaries. To mitigate the WHP increase, it should be accompanied by rate reduction not to pass the pressure limit.*
- *A wide range of injection rate is mandatory during the design of the pipeline and compression facilities, so that they would be able to cope with the gradual reservoir pressure increase throughout the injection period.*
- *Close monitoring to WHP and WHT with adequate emergency shutdown systems to avoid the risk of reservoir or cap rock fracturing during the injection process and assure CO_2 containment within the target formation.*
- *The variation of the ambient temperature for the land and underwater pipeline through the year, and the geothermal gradient for the injection well, as it might have a serious effect on the CO_2 phase behavior. Therefore, thermal isolation or additional heating and compression station may be considered.*
- *The risk of hydrate formation through the pipelines should be studied, especially at the regulation valve points, to void pipe plugging.*

Three scenarios of BHP evolution were simulated to represent the CO_2 behavior through the wellbore, shown in Figure 3.7, with injection rate 16.5 (kg/s) and WHT (50 C) to be sure that no phase change occurs inside the well, keeping the supercritical phase. WHP is in a range of (48.5 – 68 bar), while BHP is constrained between (79 – 145 bar) and injection rate 16.5 kg/s, with WHT (50 °C) & BHT (42 °C).(Pertuso, under preparation)

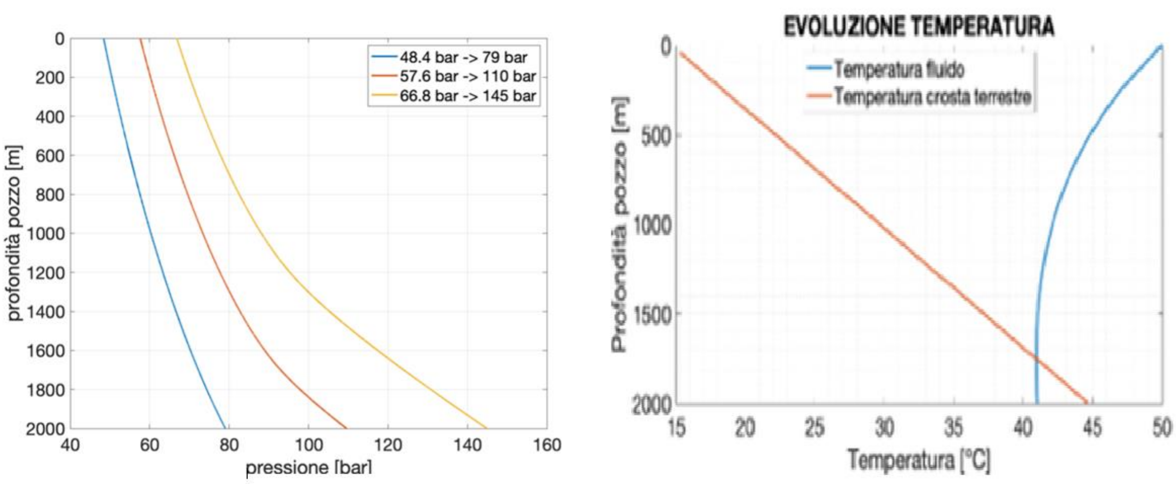


Figure 3.7 GREEN1 Pressure & Temperature behavior vs Well depth.(Pertuso, under preparation)

4. Challenges in Offshore Environment

Although the presence of the underground reservoir in offshore environment doesn't change the reservoir nature than in onshore environment, it has a big difference on the handling facilities due to many reasons. Mainly, HSE and the high cost of offshore operations are the reason behind this difference. In this chapter, the potential challenges of CO_2 storage in depleted reservoirs are addressed. And the possible handling procedures are presented at the end of the chapter to support the design of GREEN1 platform for CO2 geo-storage in depleted reservoir.

4.1. Change in In-situ Stress Field

The fact of re-injecting a fluid into underground reservoir after being depleted and increasing the pore pressure back to the initial reservoir pressure, pursue the geomechanical stress performance of the porous rock. According to Terzaghi principle of effective stress (1936), "*All measurable effects of a change of stress such as compression, distortion, and a change of shearing resistance, are due exclusively to changes of effective stress"*. Thus, regarding the reservoir pressure history, depletion during oil or gas production results in an increase of the effective stress on the rock matrix. This change in the stress causes rock compaction with deformation, permeability, and porosity reduction; especially, in the vicinity of wellbore area. The reduction in porosity will decrease the reservoir storage capacity, while the permeability reduction will negatively affect CO_2 injectivity. *(Soares et al., 2003)* Also, CO_2 injection into a fully or partially brine saturated reservoir may cause a considerable reduction in rock strength, due to the mechanical weakening of cementing material and grain contacts. This mechanical weakening is caused by rock mineral dissolution that alters the reservoir rock pore structure, resulting in a change in effective stress field and a reduction in reservoir fracture pressure. *(Rathnaweera et al., 2018)*

In general, stress path prediction is a challenging parameter to obtain; especially, when pore pressure is subjected to a change because of the hysteretic behavior of the loading and unloading stress path, regardless the chemical reactions and rock fluid interactions. Thus, it is hardly possible to restore the permeability and injectivity to the pre-depletion conditions by repressurizing the reservoir to the initial pore pressure value. *(Holt et al., 2016)*

4.2. Fines Migration and Salt Precipitation

Mobilization of fines mainly depends on reservoir minerals, permeability, stresses and pore structure, in addition to the pH of water in pores, flow turbulence and fluid viscosity.*(Hibbeler & Chavez, 2003)* Fines migration within the reservoir happens when the particles, that are loosely attached, be detached from their positions due to one or some of the reasons mentioned above, and transported through pores where they might plug or bridge the fluid flow, and subsequently cause serious reduction in permeability and injectivity.

Other than fine sand migration, the precipitation of salts due to evaporation of water and rock drying near the wellbore region caused by the mass transfer and diffusion between the injected CO_2 and reservoir connate water might also cause formation damage and reduction in the permeability around the wellbore. *(Burton et al., 2009)* However, mineral dissolution can exist after the chemical reaction of CO_2 and water producing carbonic acid that reacts with reservoir rock grains, especially carbonate rocks, i.e., limestone and dolomite, creating micro channels with an increase in porosity and permeability followed by better injectivity. In this case, the overall rock dissolution decreases as the distance from the injection well increases.*(Singh et al., 2018)*

In case of oil reservoir, when CO_2 gets in contact with oil, the equilibrium conditions after the miscibility of CO_2 in oil might result in deposition of asphaltenes and organic scales (wax and paraffin), based on the heavy components content and composition of the oil (°API). Precipitation of these solid particles can cause not only pore plugging and formation damage but also might alter of the rock wettability. Both cases can have serious consequences on the multiphase flow behavior during CO_2 injection and the plume containment inside the reservoir trap.

4.3. Residual Gas in Reservoir

Research results suggest that the residual gas present in the reservoir before implementing CO_2 storge process reduces the injectivity of CO_2 by reducing the mobility of the brine that has to be displaced by the injected gas due to the gradual increase in gas saturation causing the preference of gas to flow through the pores trapping and bypassing brine water. Additionally, the tendency of the gas plume to expand farther from the injection well as residual gas is incorporated into the mobile gas plume. The expansion of the plume is greater when the residual gas is methane CH_4, with its much lower density than supercritical CO_2, which excessively decreases the plume density, resulting in a larger plume volume. When a closed reservoir is considered, pressure can increase significantly during injection, which in turn increases CO_2 density, creating a plume that grows more slowly as time goes on. *(Oldenburg & Doughty, 2011)*

Oldenburg and Doughty *(2011),* also presented the density and viscosity of variable gas mixture compositions, between pure CO_2 and pure CH_4, as a function of pressure at reservoir temperature 40°C and 90°C, shown in *Figure 4.1*. The properties of the mixture strongly vary with the degree of impurity at all pressures, especially at pressures higher than CO_2 critical pressure (73.8 bar).

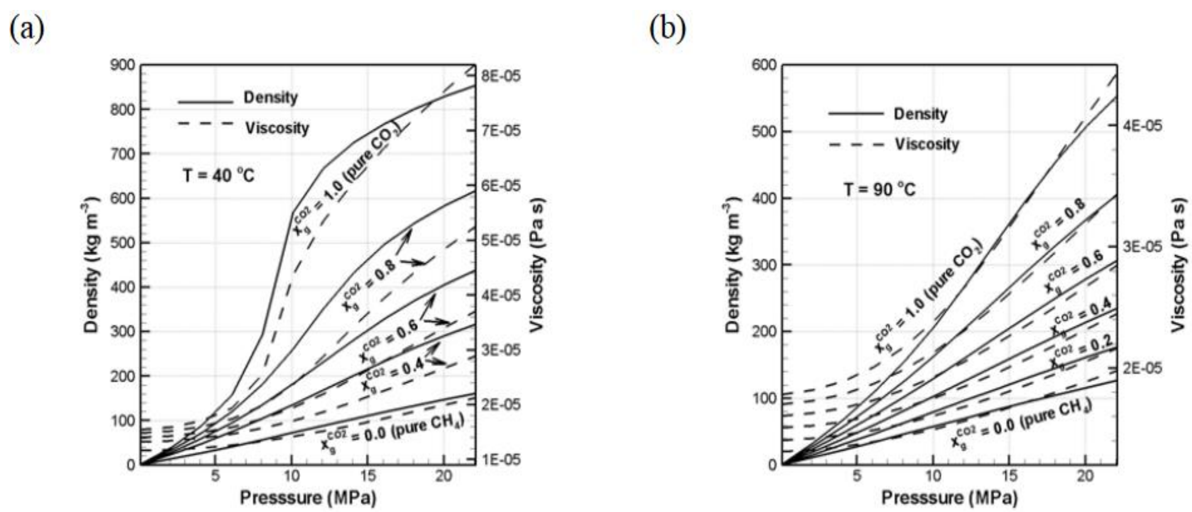


Figure 4.1 Variation of gas density and viscosity as a function of CO_2-CH_4 mole fraction and pressure at (a) 40°C and (b) 90°C

As a result of the variation in density and viscosity, the relative permeability of the new gas mixture is different. *Figure 4.2* shows the relative permeability of the gas phase is higher in case of absence of residual gas in reservoir, represented by the red lines; compared with a porous media that is primarily saturated 20% by a gas phase, represented by the blue lines.

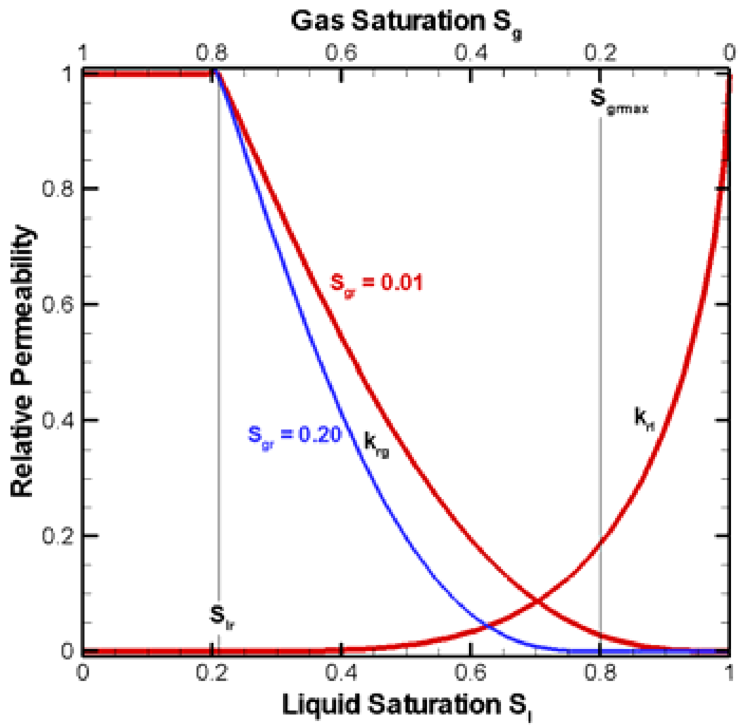


Figure 4.2 Gas and liquid relative permeability as a function of liquid saturation (Oldenburg & Doughty, 2011)

However, simulation results confirmed that CO_2 is both denser and more viscous than CH_4 under all conditions of gas reservoirs. Consequently, the injected CO_2 would migrate downwards inhibiting the mixing of the gases, and furthermore, viscous fingering may not take place because the mobility ratio (the ratio between mobility of displacing fluid to displaced fluid) is always less than one. *(Hughes et al., 2012)* By minimizing the spreading and mixing of CO_2 into residual CH_4, by reducing conformance effects, CO_2 injection in depleted gas reservoir can be exploited as enhanced gas recovery (EGR) method for the remaining gas in place.*(Abba et al., 2017; Mamora & Seo, 2002)*

4.4. Impurities in CO_2 Stream

CO_2 gas captured from different sources is usually impure, as a result of minimizing the capturing costs, as a high CO_2 purity requires more energy; therefore, a balance between cost, environmental, and legal aspects is usually recommended. The impurities, such as nitrogen, oxygen, argon, hydrogen sulfide, and methane, etc. change the CO_2 phase diagram and critical properties the mixture. *(Li et al., 2009, 2011)*

The change of the critical pressure and temperature can be serious, and the new mixture would follow a completely different phase and volumetric behavior. *Nazarian et al., (2013)* showed the variation in P-T phase diagram of two CO_2 streams with different composition and purity. In *Figure 4.3*, Mixture A is a CO_2-rich injection stream, typically from amine CO_2 separation process, with CO_2 mole fraction above 98%, with T_c=30.06 °C and P_c=74.52 bar. While in *Figure 4.4*, composition B with a CO_2 mole fraction around 90% has T_c=47.08 °C and P_c=78.85 bar. Therefore, in a storage reservoir with initial pressure 100 bar and initial temperature 37 °C, represented in the two figures, mixture A is in supercritical state that follows a gas-like behavior, while mixture B is a liquid with higher density than mixture A. This difference in phase can totally change the design of the injection plan and site preparation, i.e., heat exchangers, compressors, or pumps.

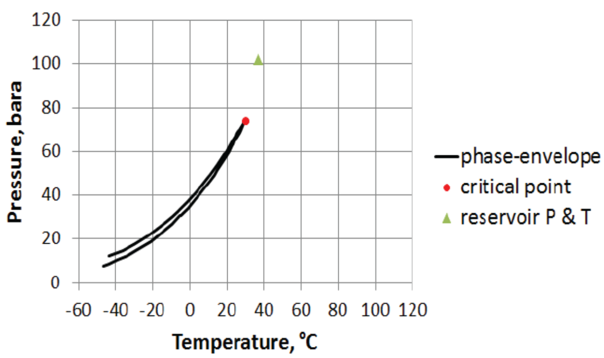


Figure 4.3 P-T diagram of CO_2 injection stream (mixture A 98% CO_2)(Nazarian et al., 2013)

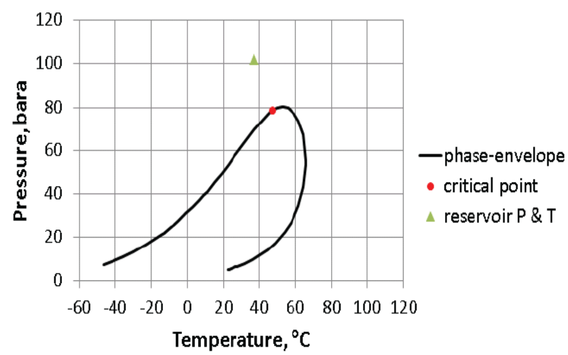
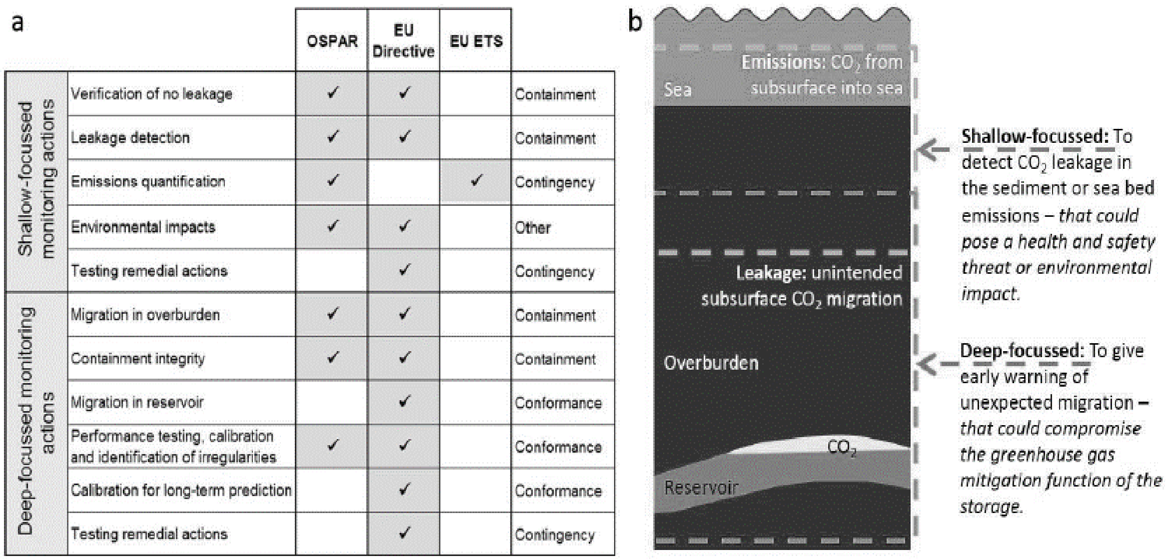


Figure 4.4 P-T diagram of CO_2 injection stream (mixture B 90% CO_2)(Nazarian et al., 2013)

4.5. Offshore Monitoring

International restrictions on offshore geological storage of CO_2 were modified in 2007 by amendments to the London Protocol and the OSPAR Convention (Oil Spill Prevention, Administration and Response). Both established similar two-stage monitoring guidelines. As Represented in *Figure 4.5*, the first stage is for monitoring the performance of CO_2 in the storage reservoir and detecting leaks at depth. The second stage is for environmental assessment in case of a leak is suspected, which then requires monitoring of the seabed and marine life.*(Hannis et al., 2017)*



	a	OSPAR	EU Directive	EU ETS	
Shallow-focussed monitoring actions	Verification of no leakage	✓	✓		Containment
	Leakage detection	✓	✓		Containment
	Emissions quantification	✓		✓	Contingency
	Environmental impacts	✓	✓		Other
	Testing remedial actions		✓		Contingency
Deep-focussed monitoring actions	Migration in overburden	✓	✓		Containment
	Containment integrity	✓	✓		Containment
	Migration in reservoir		✓		Conformance
	Performance testing, calibration and identification of irregularities	✓	✓		Conformance
	Calibration for long-term prediction		✓		Conformance
	Testing remedial actions		✓		Contingency

Figure 4.5 (a) Key monitoring actions for offshore storage required under the European regulatory framework; (b) shallow and deep focused monitoring regimes.(IEAGHG, 2015)

Monitoring objectives require that various parameters to be conducted using a range of techniques at various depths from the reservoir through the overburden to the seafloor. The regulatory requirements also mean that monitoring must be conducted at a range of spatial scales, from the entire footprint of the storage reservoir, including the area that could be affected by the migrating plume or elevated pressure field, to detailed monitoring of specific pathways that could pose a higher risk of leakage. The ability to compare data sets collected at different times and with different instruments should be maintained. Establishing baseline conditions that may require multiple measurements in dynamic systems of those parameters that are expected to evolve over the duration of project operation is considered fundamental. Such baseline conditions are an important input to the definition of normal, alert and threshold values. *(IEAGHG, 2015)*

Many of the technical challenges posed by the objectives of the regulations (conformance, containment, contingency) are not exclusive to offshore, but the offshore environment presents special challenges as follow:

4.5.1. Spatial Coverage

A challenge for both onshore and offshore monitoring is covering large areas corresponding to the footprint of a storage area (tens to hundreds of km^2), and to enable accurate measurements and characterization over extended periods of time, at specific leakage risk points such as the injection well, abandoned wells, etc. Current research studies on emissions detection are mainly focused on passive acoustic sensors (listening for bubbles) or chemical detection (pH change). The development of hyperspectral imaging systems for the deep sea is also promising, which can be configured to perform wide areal range surveys of seafloor biological communities for both baseline surveys and periodic monitoring. Furthermore, Monitoring systems should be able to cover large areas in a reasonable length of time but also detect small discrete features. *(Hannis et al., 2017)*

4.5.2. Baselines

Baselines are a necessary requirement for all types of monitoring, both surface and downhole based. By a surface seismic survey, specially designed pre-injection baseline survey that covers the entire storage area is the optimal solution from a technical standpoint. In practice, there are some options that can improve cost efficiency and reduce environmental impact.

The baseline issue for shallow monitoring is complex, and it is critical that measurements to be made so that anomalous emissions can be identified. However, since any deviation from baseline could be considered an 'emission', it is equally important that baseline data sets capture the full range of natural variations to avoid false interpretation. Because of the wide range of spatial and temporal variations in several processes, repeated monitoring of baseline data is likely to be required to establish these natural cycles. These baseline data could also be collected during the injection period if there is no evidence of significant irregularities where the system could change due to factors such as increasing seawater acidification or temperature rise. Therefore, robust offshore baselines must cover a wide range of environmental variables based on the storage situation. *Table 4.1*, is a list of the issues relevant to a range of monitoring methodologies and some recommended baseline sampling strategies depending on the situation. *(Dean et al., 2020)*

Table 4.1 An overview of the spatial and temporal criteria for baseline data acquisition.(Blackford et al., 2015)

Method	Variables	Temporal sampling interval	Spatial sampling scale	Notes
Active acoustics	Sea floor bathymetry, including pockmarks.	In shallow waters where the seafloor sediments are exposed to storm driven re-suspension and biological sedimentation a seasonal discrimination, in the first instance. In deeper waters where sediments are disconnected from weather driven events an initial survey, followed by a repeat survey 1-2 years later.	The spatial extent of the storage reservoir in addition to allowing for lateral movement of migrating CO_2.	Assists identification of existent natural seeps.
	Free gas in surface sediments.	An initial survey, followed by a repeat survey 1-2 years later.		Useful for attribution.
Passive acoustics	All noise at relevant frequencies.	Seasonal in addition to targeted short term deployments to assess event driven noise.	Targeted to known fixed installations or shipping routes.	Necessary for quantification, not essential for detection.
	Acoustics of existent natural gas seeps.	Seasonal and targeted short term deployments to account for intermittent gas flow.	Spatial extent of the storage reservoir as well as allowing for lateral movement of migrating CO_2	Required for detection.
Geochemistry	pH, pCO_2, temperature, salinity, pressure. TA or DIC and O_2 if possible.	Hourly measurements for at least part of the seasonal cycle, corresponding with periods of biological or physical activity. Weekly for entire annual cycle. Repeated for at least one subsequent year to assess inter-annual variability and then on an approximately decadal repeat to assess longer term trends.	For high frequency data, if the storage site is large or includes significant changes in water depth or other hydrodynamic properties, at least a pair of landers deployed across the site. Spatial extent of the storage site via AUV deployment.	Required for detection.
Biology	Community structure, indicator species and related indices.	Weekly during periods of intense biological activity, otherwise monthly. Repeated for at least one subsequent year to assess inter-annual variability and then on an approximately decadal repeat to assess longer term trends.	Significant differences in water depth and-or different sediment types within the complex would need separate characterisation. Multiple replicates are required for statistical certainty.	Principally for impact assessment.

4.5.3. Logistics and Processes

Compared to onshore, the offshore is logistically remote and difficult to access, which means offshore operations can be very expensive, especially if operation ship or barge time is involved. Health and safety are paramount, and only proven and approved operational procedures must be considered (like HSE protocols for offshore platforms).

Water depth and temperature affects both the logistics of deploying survey equipment, and the nature of CO_2 emissions in the sea water column. For example, bubble size and bubble dissolution rate will be a function of water depth, temperature, and salinity etc. Also, disturbance of the water column will define the rate at which local emissions of CO_2 dissipated into the wide marine environment, which in turn will have an influence on the required sensitivity of instruments and their spatial coverage.

Also, anthropogenic activity can have effects on the seabed that might be indicative of emissions. It might destroy the in-situ monitoring equipment. For example, wind farms are recently an increasing component of offshore infrastructure. The turbine installation and foundations will affect the logistics, coverage, and quality of monitoring surveys.*(IEAGHG, 2015)*

GREEN1 conversion plan must be as accurate and robust as possible, considering all risks and possible scenarios. For that, the discussed above challenges can be handled as follow:

- *If possible, Formation Integrity Test (FIT) should be performed prior the CO_2 injection process to assure the integrity of reservoir formation, as the in-situ stresses might have been changed due to reservoir depletion at the production time.*
- *Not only computational simulations should be done to confirm the compatibility of the injected CO_2 with the reservoir fluids, but also core analysis in the lab should be done to check the physical and chemical interactions between CO_2 and reservoir and cap rock.*
- *The residual gas in a depleted reservoir can be extracted by a good CO_2 EGR plan and appropriate injection/producer well distribution within the reservoir. Nevertheless, it might reduce the CO_2 storge capacity, due to the expansion of the plume volume as a result of the low density of CO_2-CH_4 mixture.*
- *If the reservoir pressure and temperature values are near the CO_2 critical pressure and temperature, it is preferred to have highly pure CO_2 injection stream to avoid the transformation of the injected CO_2 to liquid phase inside the reservoir, which in turn would have negative effects on the fluid injectivity. However, after a sufficient increase in reservoir pressure, it is possible to have a less pure CO_2 stream.*
- *Establishing an accurate monitoring baseline in offshore environment require the understanding of not only current marine nature, but the possible future anthropogenic activities in the area also should be considered. That might require smaller spatial distance between detectors and/or higher recording frequency.*

5. Identification of Candidate Sites

By analogy to the common quote *“More important than treating a disease is diagnosing it.”*, the identification of the suitable sites for CO_2 geo-sequestration is crucial for all the design parameter that follow it. Furthermore, it even can affect the design and selection of the carbon capturing plant place, capacity, and the degree of CO_2 purity. Fortunately, there are quite enough data available for the diagnosis in case of the depleted reservoirs under investigation in the north Adriatic Sea area for the process of converting a present production platform, instead of decommissioning it, for CO2 storage. In this chapter, the main reservoir characteristics to be studied for further screening of the candidate sites are examined.

5.1. Storage Capacity

Reservoir storage capacity for carbon dioxide is a main parameter to decide whether it is economically efficient to go on with the injection plan or to find another candidate reservoir. For depleted oil and gas reservoirs it is easier to estimate the storage capacity, as there are historical production data and geological models that are already built and matched throughout the field production life. While in saline aquifers, stratigraphical model, geophysical, and petrophysical data are to be constructed for the aquifer. As a result, beside the high uncertainty of the data obtained, without model history match in saline aquifer, the economic cost is very high.

Liang et al., (2009) assessed the capability of 183 mature oil reservoirs close to Dongying city in China, near to CO_2 emission sources, they found out that only 41 reservoirs are suitable for CO_2 storage, 23 of them are depleted oil reservoirs. In their study, they avoided the complexity of development modes and reservoir conditions and considered the main parameters influencing storage process i.e., CO_2 sweep efficiency and API gravity of crude oil. They also excluded the heavy oil reservoirs and reservoirs with pore deformation around producing wells, while the main factor for selection was the storage capacity, where they found a nearly linear relationship between CO_2 storage potential and OOIP, *Figure 5.1*.

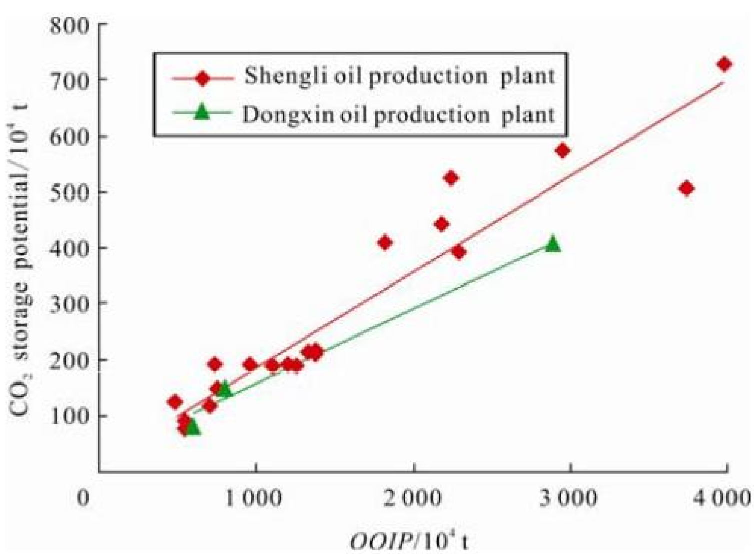


Figure 5.1 CO_2 storage potential vs OOIP for the depleted oil reservoirs. (Liang et al., 2009)

Carbon Sequestration Leadership Forum (CSLF) has proposed a method for calculating the CO_2 potential in depleted oil reservoir. This method is based on material balance equation, that CO_2 to be injected in the depleted reservoir until the initial reservoir pressure is reached. *Equations (5.1)* and *(5.2)* represent the calculation of CO_2 storage capacity in depleted oil and gas reservoir, respectively, on the basis of mass balance.*(Bachu et al., 2007)* By using these direct equations, a rough estimation of reservoir storage capacity for CO_2 is reached and different reservoirs can be compared.

$$M_{Co_2} = \rho_{Co_2r} \times (E_R \times N \times B_o - V_{iw} + V_{pw}) \qquad 5.1$$

$$M_{Co_2} = \rho_{Co_2r} \times (E_R \times G \times B_g - V_{iw} + V_{pw}) \qquad 5.2$$

Where:

$\mathrm{M_{Co_2}}$ = theoretical storage capacity [Mt]
$\rho_{\mathrm{Co_2r}}$ = density of $\mathrm{CO_2}$ in the reservoir $\left[\frac{\mathrm{kg}}{\mathrm{m^3}}\right]$
N = original oil in place OOIP [10^9 $\mathrm{m^3}$]
G = original gas in place GOIP [10^9 $\mathrm{m^3}$]
$\mathrm{E_R}$ = oil/gas recovery factor [%]
$\mathrm{V_{iw}}$ = volume of water injection in reservoir [10^9 $\mathrm{m^3}$]
$\mathrm{V_{pw}}$ = volume of water production [10^9 $\mathrm{m^3}$]
$\mathrm{B_o}$ = oil formation volume factor $\left[\frac{\mathrm{m^3_{res}}}{\mathrm{m^3_{sc}}}\right]$
$\mathrm{B_g}$ = gas formation volume factor $\left[\frac{\mathrm{m^3_{res}}}{\mathrm{m^3_{sc}}}\right]$

By applying *Equation 5.2* in the case of 'Porto Corsini Mare' reservoir, found the reservoir capacity around 2.1 Mt CO_2. For the calculation, Due to unavailability of PVT data of the reservoir gas, considered 95% methane and 5% ethane, therefore, $B_g = 6.09 \times 10^{-3}$ m^3/sm^3 (compressibility factor Z = 0.8), $\rho_{co2} = 717$ kg/m^3 at P=145 bar & T=45°C.*(NIST, 2022)*

5.1.1. Trapping Mechanisms

For more accurate storage capacity estimation, other variables should be added to the above-mentioned method. As the injected CO_2 doesn't only replace the produced oil or gas but also there are other physical and chemical trapping mechanisms co-exist with the structural and stratigraphic trapping; like mineral precipitation, when CO_2 reacts with existing rock to form new stable minerals, and dissolution of CO_2 in formation fluids during migration inside reservoir, And also when CO_2 fills interstices between the grains of the rocks which is later called residual gas *(Bradshaw et al., 2007)*. The trapping mechanisms are classified as follow:

- **Structural and stratigraphic trapping:** The most predominant trapping mechanism in oil and gas fields which is dependent on basins tectonic evolution like faults and anticlines. It has simple volume calculation of available pore space in trap, considering the factors that inhibit access to all the trap, e.g., sweep efficiency, residual oil and water saturation.

- **Dissolution:** CO_2 dissolves in formation fluid (oil, water, or both) during migration inside reservoir**.** Knowing that water salinity has a major role in CO_2 solubility in water less saline water better dissolution), while the miscibility in oil depends on pressure and contact equilibrium performance.
- **Residual gas:** when the rock matrix tends to adsorb carbon dioxide rather than the original wetting fluid, so CO_2 adsorbed to rock surface and trapped in the small pores.
- **Mineral precipitation:** the presence of reactive minerals and formation water chemistry could create or precipitate salts in the porous media that might cause clogging up the pore throats and reducing injectivity.
- **Coal adsorption:** when CO_2 preferentially adsorbs onto coal surface in coal bed reservoirs. The adsorption of CO_2 has negative influence on injectivity due to coal swelling.

5.1.2. Storage Uncertainty

The resource pyramid, *Figure 5.2*, introduced the categories of storage capacity uncertainties as follow: (a) high level, (b) techno-economic and (c) trap type and effectiveness aspects. *(Bradshaw et al., 2007)*

Theoretical capacity considers all the reservoir formation is accessible to store free-phase CO_2 in its pore volume, and all the formation water is available to have CO_2 dissolved into it, and the whole mass of coal -if exist- is available to adsorb and store CO_2 at maximum adsorption capacity. This results in a maximum upper limit to the capacity estimation. However, it is an unrealistic number, there will be technical and economic limitations that prevent parts of the reservoir formation from being accessed or fully utilized. This represents the theoretical limit of the whole geological system, and it occupies the whole resource pyramid.

Realistic capacity applies a range of geological and petrophysical cut-off limits to the parameters of assessment like the reservoir permeability and porosity, depth of burial, pressure and stress regimes, pore volume of the reservoir, and whether there are other involving elements that might be compromised by the CO_2 injection (such as oil, gas, coal, water, geothermal energy, reactive minerals). This is a more logic estimate that can be done with a good degree of precision and gives important indications of technical viability of CO_2 storage. These estimates are within the body of the resource pyramid but exclude the base part of the resource pyramid.

Viable capacity considering economic, legal, and regulatory barriers to CO_2 geological storage. A detailed source matching is performed at this stage to match the best and nearest storage sites to emission sources. The source matching should extend beyond just geoscience and engineering aspects and include social and environmental risk aspects of storage sites. Cost curves and simulations can be introduced to help estimate the level of uncertainty. Once this level of assessment has been reached, it is possible to express the capacity as an annual sustainable rate of injection, not just as a total volume. These storage capacity estimates are at the top of the resource pyramid.

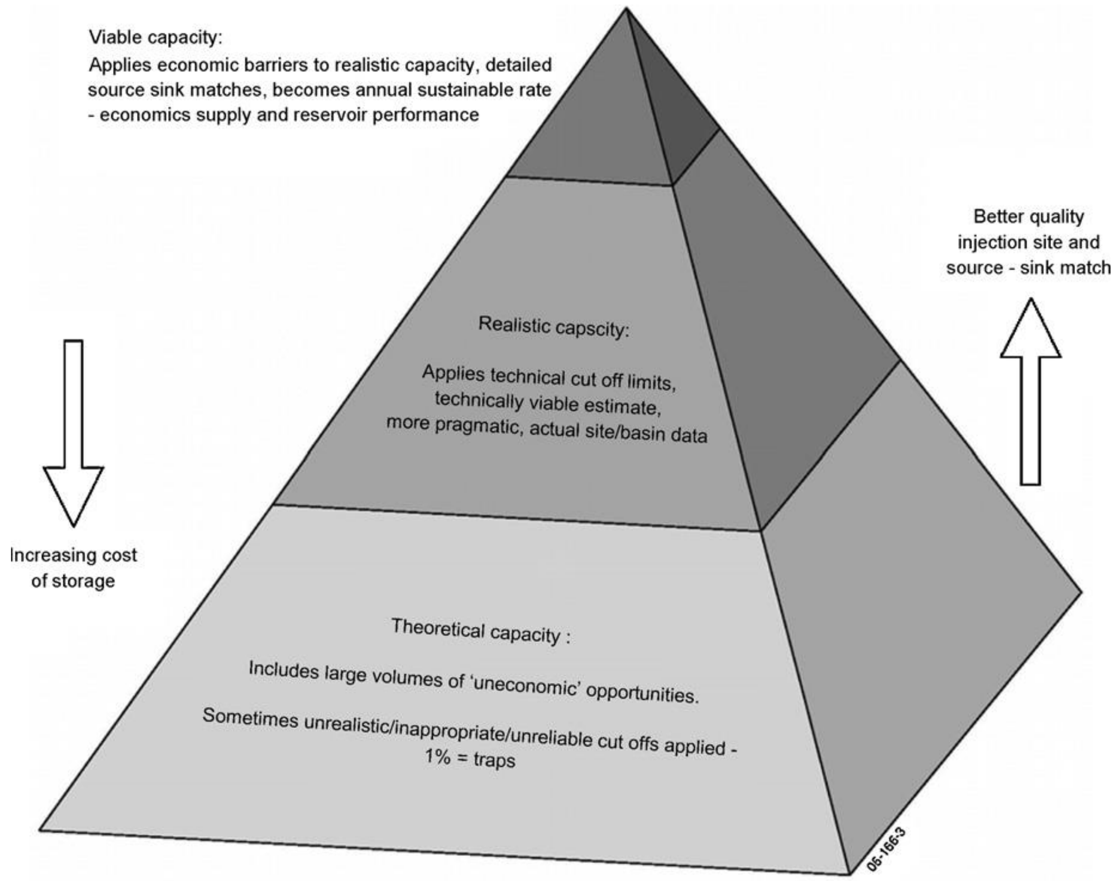


Figure 5.2 Resource pyramid for capacity of CO_2 geological storage, showing the three levels of theoretical, realistic, and viable estimates (Bradshaw et al., 2007)

Storage capacity is highly affected by reservoir properties and the interactions between CO_2 and the reservoir rock and fluids during injection period. For example, due to buoyancy and gravitational forces, injecting CO_2 down-dip of an oil/water trap, up-dip of a gas trap, or into a horizontal well will enhance the CO_2/rock contact, therefore increasing storage capacity.

As in mining resource or petroleum reserve estimates, uncertainties are introduced by deriving probability distributions for different storage categories. Using an adequate simulation tool, i.e., Monte Carlo simulation, should include probability distributions correlated with the reservoir characteristics and injection system parameters, as well as capital and operating costs of the CO_2 storage project.*(Allinson et al., 2010)*

Beside the storage capacity, the distance of carbon dioxide supply source is a key parameter for selection between depleted oil & gas reservoirs and saline aquifers, considering the transportation cost as well as compression cost.

5.2. Injectivity

Injectivity is the ability to inject CO_2 through a wellbore into underground reservoir at a defined flow rate and pressure. On surface, form the carbon capture facility to well head, CO_2 can be transported in liquid, vapor, or supercritical phase. In practical applications, injection is controlled by regulating wellhead pressure in order to deliver an acceptable downhole pressure, with the desired flow rate, that must be maintained between reservoir pore pressure and fracture pressure to be able to achieve the injectivity of CO_2 without reservoir damage.

There are many parameters to be considered during the process of candidate depleted reservoir screening based on injectivity, mainly represented by the Injectivity Index (tons of CO_2/day per bar) which defines how much CO_2 can be injected through a wellbore per day for each 1 bar differential pressure, Equation 5.3. For example, an injectivity index 2.0 tons of CO_2/day per bar, for a reservoir with static pressure 180 bar, means that we can inject 2.0 tons CO_2/day when downhole injection pressure is 181 bar, and 4.0 tons CO_2/day when downhole injection pressure is 182 bar. The Injectivity Index can be calculated by applying the appropriate well testing procedures, i.e., injectivity test, in the beginning of CO_2 injection. *(Onwuchekwa et al., 2019)*

$$II = \frac{Q}{P_{BHFP} - P_{res}} \tag{5.3}$$

Where:

II = injectivity Index $[\frac{m_{sc}^3}{\mathrm{day}} / \mathrm{bar}]$

Q = injection flowrate $[m_{sc}^3/\mathrm{day}]$

$\mathrm{P_{BHFP}}$ = bottomhole flowing pressure [bar]

$\mathrm{P_{res}}$ = reservoir pressure [bar]

As mentioned before, Injectivity is basically influenced by fluid flow dynamics in porous media. Consequently, reservoir permeability and reservoir pressure are main factors in defining the well injectivity in addition to the injected fluid properties.

Injecting CO_2 in supercritical state in a depleted low-pressure reservoir may result in CO_2 vaporizing within either the wellbore or the reservoir formation. The CO_2 vaporization process is associated with a temperature drop, variations in the thermodynamic properties of the CO_2 phases, and an increase in flow velocity due to CO_2 expansion. *(Oldenburg, 2007)* These phenomena might cause flow assurance issues like the hydrate formation, loss of pressure control, and rate fluctuations. *(Hoteit et al., 2019)*

A study results show that the injectivity of closed reservoirs falls significantly with increasing total injection rate. High quality reservoirs might use a single well to inject a large amount of CO_2 (for example, the *Sleipner* project in North Sea). Adding more wells increases injectivity, provided the formation is hydraulically well connected to surrounding lateral extension. However, with multiple wells, pressure interference between injectors is an issue. In an open system, this effect can be avoided by spacing the wells far apart. However, if the volume of the reservoir is limited, adding more wells will not significantly improve injectivity. *(Allinson et al., 2010)*

For an injectivity based screening, the reservoir permeability , particularly around the wellbore, is a key factor for selection in addition to the thickness if the injection layer. In reservoir, both permeability and net thickness are measured as one parameter (*kh*) throughout well testing, then the value is divided by reservoir thickness to get the average permeability factor. By Analogy, later in this study, the injectivity screening is based on the total (*kh*) value, not on the permeability and thickness as separate parameters, to avoid the exclusion of suitable candidate reservoirs, provided that the storage capacity is big enough for CO_2 storage.

5.3. Containment

5.3.1. Cap rock Integrity

Before implementing a CO_2 geo-storage project, two critical issues must be addressed: (1) The distribution of CO_2 inside the reservoir after injection, (2) The efficacy of the reservoir to contain the injected CO_2 permanently. Like hydrocarbon reservoirs, the behavior of multiphase flow and containment in CO_2 geo-storage is highly affected by the reservoir rock wettability, and the capillary sealing potential of the caprock overlying the potential subsurface CO_2 plume is critical to confinement of the injected CO_2. Furthermore, the relationship between capillary pressure and saturation, as well as relative permeability, is directly depending on the reservoir rock wettability. As a result, the water wet reservoirs are preferred for CO_2 storage, since unwanted plume migration risk is highest in strongly CO_2 wet reservoirs.

CO_2 seepage through the caprock occurs in case that the pressure exerted by the CO_2 plume from below is higher than the capillary entry pressure threshold that represents the minimum pressure required to displace the wetting fluid in the sealing cap rock layer. *(Metz et al., 2005)* In addition, it has been experimentally demonstrated that CO_2 can alter the original wettability of a porous media, which in turn could lead to a change in the originally predicted fluid distribution within the layer and the effectiveness of containment.*(Al-Khdheeawi et al., 2017)*

Injection of CO_2 causes a reservoir pressure increase and affects the geomechanical stresses on the cap rock. The difference in temperature between the injected CO_2 and the reservoir causes additional stresses that are developed due to thermal expansion/contraction. This phenomenon can cause fracture initiation in the cap rock leading to the loss of its integrity and containment to the injected fluid. *Gor and Prevost (2013)*, found that injecting CO_2 at a temperature of (40°C - 50°C) into 90°C reservoir (in Salah field, Algeria) will produce 50 meter fracture in the cap rock after 10 years of injection.

5.3.2. Existing Wells

Regarding well containment, the small number of wells penetrating saline aquifers becomes an advantage over depleted oil and gas reservoirs which are intersected by tens, if not hundreds, of wells, some of which were drilled decades ago. Nonetheless, the age of the well does not mean that they are sealed or not, other factors are involved, i.e., completion type, level of activity, and abandonment regulations, etc. For example, the incidence of channeling due to poor mud removal has likely declined as the causes and mechanisms are now well understood and adequate preventive measures are routinely taken, reducing the risk of leakage from newly drilled wells.*(Loizzo et al., 2010)* The resulting high uncertainty regarding the containment and seal ability of existing wells has to be aggressively investigated to characterize and repair any well to be in contact with the plume, including abandoned wells, particularly in offshore fields, as they might represent a short circuit to the surrounding formations or to the open atmosphere. *Figure 5.3* shows all the possible leakage paths for an existing well through a cased and cemented well intersecting the storage formation. The leakage can occur due to a poor cement bond between the casing steel and cement, between the formation rock and cement, or even through a cement plug inside an abandoned well.

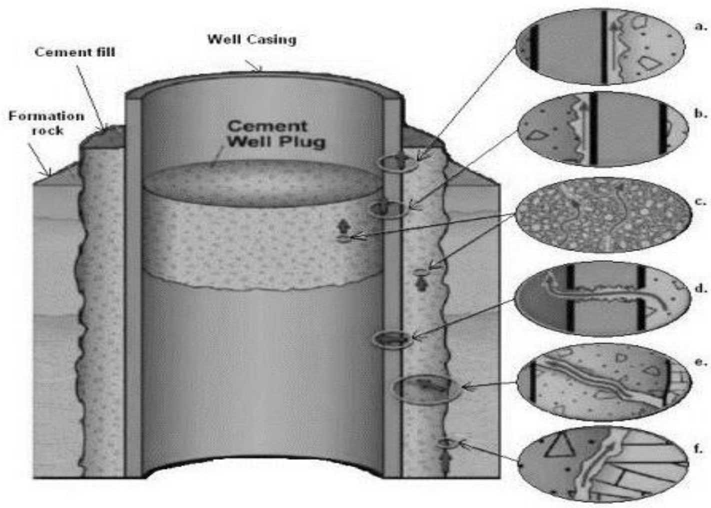


Figure 5.3 Possible CO2 leakage paths through a cemented casing. a), b) & f) leak paths due to poor bonding between cement and casing/formation; c) fluids migration due to cement fracturing; d) leakages occurring for casing failure; e) flow path through the cement layer due to gas migration during hardening.

5.3.3. Monitoring

The key objective of the monitoring program is to provide a robust 3D volumetric representation of the reservoir so that CO_2 migration is effectively mapped both within the reservoir and into adjacent strata. Ideally, monitoring will show that CO_2 is fully contained within the reservoir. However, if this is not the case, it should provide early warning of migration into the overburden and, in the future, possible migration toward the surface atmosphere. *Figure 5.4*, shows the extension of the CO_2 plume through three years of injection, from 1999 to 2002 in three layers of *Sleipner* field in Norway, and prove the containment of the injected fluid within the target reservoir.

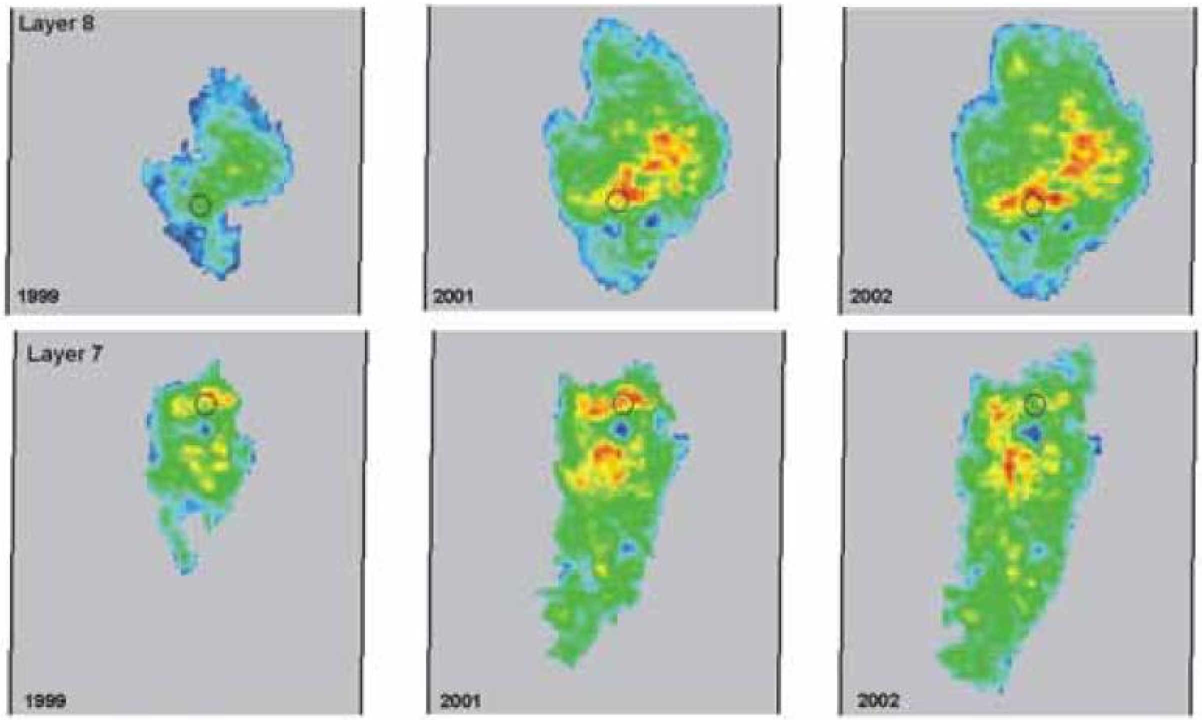


Figure 5.4 Reflection amplitude maps of two layers of the Sleipner field showing CO_2 plume growth from 1999 to 2002. (R. A. Chadwick & British Geological Survey, 2008)

5.3.4. Faults and Seismicity

The initial structural framework should highlight features such as faults and folds that can control fluid flow. In some cases, multiple suitable injection zones may occur at different depths and should be mapped and evaluated. The accuracy of the stratigraphic and structural model depends on the density of available data in the area. Analysis of existing seismic data should be considered to supplement the well data. The seal ability and characteristics of faults can be verified through the appropriate well testing.*(NETL, 2017)* Furthermore, the presence of active faults or high seismic activity in the site increases the risk of potential leakage of CO_2 throughout uncontrolled underground migration or up to surface. *Figure 5.5* shows that the seismic activity in the northern Adriatic Sea is low to moderate, that makes it quite suitable for underground CO2 storage.

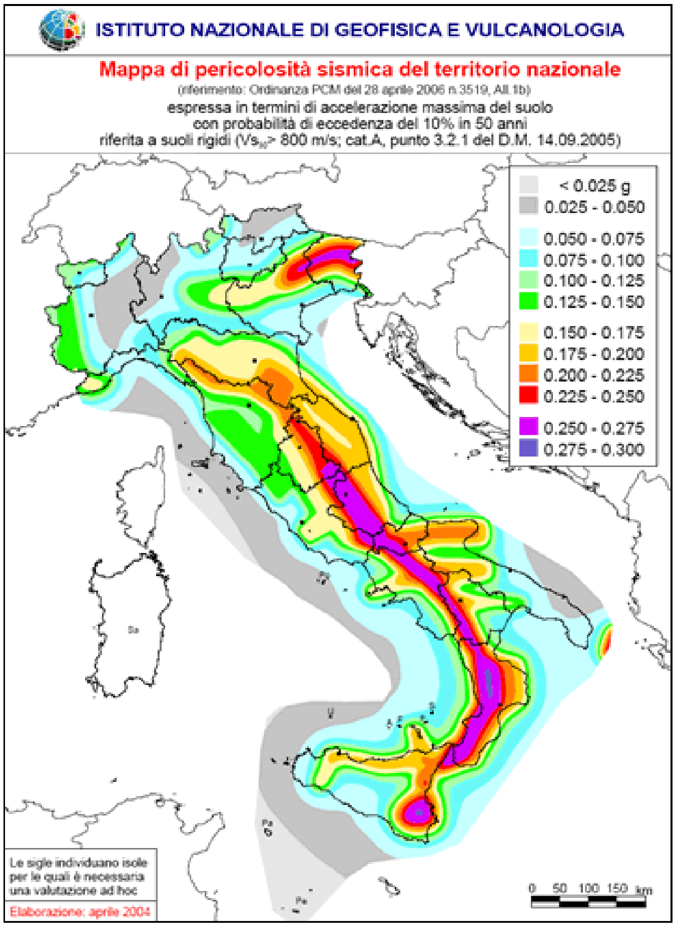


Figure 5.5 Seismic hazard map of the Italian territory.(Manfredi & Masi, 2018)

The depleted reservoirs have the advantage for CO_2 storage over saline aquifers due to their assurance regarding storage capacity, injectivity, and containment. However, the existing wells conditions might represent a high risk of CO_2 leakage out of its trap. The abandoned wells integrity and cement bond between well and reservoir are critical issues for containment. Thus, during the study of converting the platform GREEN1, a clear and deep analysis for all the wells that would be in contact with the CO_2 plume (not only the wells of the platform) must be performed. Also, an economic and risk assessment should be taken into consideration for any future well interventions. Nonetheless, adequate knowledge of the cap rock nature and its long-term interaction with trapped plume is mandatory in additional to the possible seismic and faults activity in the area.

As an example, the storage capacity of 'Porto Corsini Mare' reservoir was calculated using Equation 5.2 to be (2.1 Mt) of CO_2 , which is quite small volume. However, the selection decision should be based on an economic study with a comparison among the other available sites in the area.

6. Site Screening and Selection

In this part, a deep and intensive bibliographic study about all the involved reservoir parameters to be considered during the selection of the suitable CO_2 geo-sequestration sites is introduced, with a development of a logic map that serve the examination of the available reservoirs for defining and selecting the most appropriate offshore installation to be our GREEN1 platform, out of 99 candidate Italian platforms in the Adriatic Sea .

6.1. Site Screening

Few screening criteria for the underground CO_2 storage selection were studied in the last two decades to provide a good methodology and clear insight for the selection of a storage sites. These studies were based on some key parameters including reservoir and well characteristics, rock and mineral classes, fluid saturations, subsurface pressure and temperature, wettability, containment potential, and CO_2 properties.

Chadwick et. al, *(2008)* proposed a report, sponsored by the EU industry and national governments, regarding the screening and selection of saline aquifers compatible for CO_2 storage. Their screening phase evaluated the ability of storing CO_2 in a suitable region by identifying, evaluating, and comparing potential storage sites. It typically used existing data sets to rank storage sites based on geologic, economic, environmental, and logistic considerations from the experiences of five CO_2 injection case studies in Europe. The key geologic selection parameters included depth, thickness, porosity, permeability, seal integrity, and salinity of the reservoir (*Table 6.1)*.

Table 6.1 The screening criterion for the CO_2 storage in saline aquifers, proposed by Chadwick et al. (2008)

Parameters	Positive indicators	Cautionary indicators
Total storage capacity	Total capacity of reservoir estimated to be much larger than the total amount produced from the CO_2 source	Total capacity of reservoir estimated to be similar or less th amount produced from the CO_2 source
Depth	1000–2500 m	<800 m or >2500 m
Thickness (net)	≫50 m	<20 m
Porosity	>20%	<10%
Permeability	>300 mD	10–100 mD
Salinity	>100 g/L	<30 g/L
Seal properties		
Lateral continuity	Un-faulted	Laterally variable faults
Thickness	>100 m	<20 m
Capillary entry pressure	Mush greater than buoyancy force of maximum produced CO_2 column high	Similar to buoyancy force of maximum produced CO_2 colum

IEA Greenhouse Gas R&D panel (2009) performed a two stages process for screening, so that the unsuitable sites to geological storage are removed, represented in *Table 6.2*. The first stage is an elimination process, where sites are screened out completely due to the lack of critical characteristics for CO_2 storage, i.e., insufficient capacity or lack of sealing integrity. The second stage then assesses the sites that have passed the elimination process and screens them using a set of parameters to detect the most favorable sites for further investigation. Sites can still be rejected if there are too many undesired conditions. The exclusion criteria fall into two categories: a) Critical, these criteria must be achieved without exceptions; and b) Essential, these criteria should also be met, but exceptions may occur depending on exceptional circumstances. The study concluded that the main reservoir characteristics required for CO_2 storage are:

- Porosity and thickness, to create adequate storage capacity,
- Permeability, to be high enough to allow injection,
- The presence of at least one or more confining layer to prevent leakage and migration of the injected CO_2.

Table 6.2 Site screening criteria for CO_2 storage, by the IEAGHG (2009)

Criterion Level	No	Criterion	Eliminatory / Unfavorable	Preferred / Favorable
Critical	1	Reservoir-seal pairs; extensive and competent barrier to vertical flow	Poor, discontinuous, faulted and/or breached	Intermediate and excellent; many pairs (multi-layered system)
	2	Pressure regime	Over-pressured: pressure gradients greater than 14 kPa/m	Pressure gradients less than 12 kPa/m
	3	Monitoring potential	Absent	Present
	4	Affecting protected groundwater quality	Yes	No
Essential	5	Seismicity	High	Moderate and less
	6	Faulting and fracturing intensity	Extensive	Limited to moderate
	7	Hydrogeology	Short flow systems, or compaction flow; Saline aquifers in communication with protected groundwater aquifers	Intermediate and regional-scale flow
Desirable	8	Depth	< 750-800 m	>800 m
	9	Located within fold belts	Yes	No
	10	Adverse diagenesis	Significant	Low to moderate
	11	Geothermal regime	Gradients ≥ 35 ºC/km and/or high surface temperature	Gradients < 35 ºC/km and low surface temperature
	12	Temperature	< 35 ºC	≥ 35 ºC
	13	Pressure	< 7.5 MPa	≥ 7.5 MPa
	14	Thickness	< 20 m	≥ 20 m
	15	Porosity	< 10%	≥ 10%
	16	Permeability	< 20 mD	≥ 20 mD
	17	Caprock thickness	< 10 m	≥ 10 m
	18	Well density	High	Low to moderate

Ramírez et. al, *(2010)* applied a methodology for screening and ranking the Dutch reservoirs suitable for long-term storage of CO_2 , *Table 6.3*. The screening focuses on individual offshore and onshore aquifers, oil and gas fields. After screening, a total of 176 storage sites were considered: 138 gas fields, 4 oil fields, and 34 aquifers, with a total theoretical storage potential of about 3200 Mt CO_2. The storage sites were reviewed based on three main criteria: potential storage capacity, storage cost, and risk management effort. A spreadsheet tool was developed to allow evaluation of each criterion through an evaluation of the fields available in the database and a series of evaluations by a panel of experts.

Table 6.3 Thresholds used for the pre-screening of CO_2 storages in The Netherland (Ramírez et al., 2010)

Parameter	Threshold
Capacity	≥4 Mt for gas/oil and ≥2 Mt for aquifer
Thickness reservoir	>10 m
Depth top reservoir	≥800 m
Reservoir porosity	Aquifers: >10%
Reservoir permeability	Aquifers: an expected permeability of 200 mD or more
Thickness seal	≥10 m. Both simple seals as well as complex seal have been taken into account
Seal composition	Salt, anhydrite, shale or claystones
Reservoir composition	Aquifers: sandstone, hydrocarbon fields: limestone, sandstone, siltstone, carbonates
Initial pressure	Overpressure excluded
Salt domes	Relevant for aquifers. Traps located alongside/near salt domes/walls have been excluded because there is a high risk of salt cementation

The screening criteria are developing every year, and extra selection parameters are added continuously. For depleted gas reservoir to be reused in CO_2 storage, specifically those fields with offshore production platforms, as the costs of decommissioning such platforms are high, in addition to legal and environmental consequences, a deeper investigation is mandatory through the history and the nature of the gas reservoir. The reservoir pressure and residual gas in place are key factors, in addition to the distance from the shoreline to the platform and the ambient temperature of seawater in the area.

Raza et. al, *(2016)* investigated further selection parameters as reservoir and well types, mineral classes, residual gas and water saturations, subsurface conditions, rock types, wettability, properties of CO_2, and sealing potentials. These parameters were combined with factors already presented before to provide good insight into appropriate reservoir selection. In *Table 6.4*, adequate permeability and thickness should be present for successful injection. Also, the presence of horizontal or vertical wells with hydraulic fractures and good completions improves a site's ability to allow higher CO_2 injection rates. Additionally, the status of faults and fractures, subsurface conditions, rock and fluid properties should also not be neglected to have a safe and secure storage medium.

Table 6.4 Screening criterion for selection of depleted gas reservoirs, by (Raza et al., 2016)

Parameters	Positive indicators	Cautionary indicators	Indication of aspect
CO_2 source and total storage capacity	Total capacity of reservoir estimated to be much larger than the total amount produced from the CO_2 source	Total capacity of reservoir estimated to be similar or less than the total amount produced from the CO_2 source	Storage potential
Depth	>800 m	800 m > depth > 2000 m	Storage capacity
CO_2 density	High	Low	Storage capacity
Porosity	>20%	<10%	Storage capacity capillary trapping
Thickness (net)	≫ 50 m	<20 m	Storage capacity injectivity
Permeability (near-wellbore)	>100 mD	10–100 mD	Injectivity
Well type	Horizontal well with or without hydraulic fracture/vertical well with hydraulic fracture	Vertical well without hydraulic fracture	Injectivity
Type of minerals	Ca-, Mg-, or Fe-rich framework minerals such as (feldspars, clays, micas, and Fe-oxides	Fast reacting carbonates minerals	Injectivity/ mineral trapping
Residual gas/water saturation	Less	High	Injectivity
Pore throat size distribution	Less heterogeneous	High heterogeneous	Injectivity and trapping
Salinity	Low	High	Solubility trapping
Temperature	Low temperature gradient	High temperature gradient	Solubility trapping
Pressure	Under pressure	overpressure	Solubility trapping
Gravity number	Less	High	Capillary trapping
Rock type	Quartz rich sandstones and carbonates	Highly stress sensitive carbonates	Capillary trapping
Rock wettability	Strong water wet	Less water wet or oil-wet	Capillary trapping
Interfacial tension	High	Low	Capillary trapping
Hydraulic integrity – Reservoir type	Reservoir without compaction/aquifer support Have not experienced any injection in past Less faults and fractures	Reservoir with compaction/aquifer support Have experienced any injection in past More faults and fractures	Containment
Hydraulic integrity – Well location & condition	Good completion condition and away from faults & fractures	Poor completion and near to faults & fractures	Injectivity
Seal capacity – CO_2 column height	Capillary entry pressure much greater than buoyancy force of maximum produced CO_2 column high	Capillary entry pressure similar to buoyancy force of maximum produced CO_2 column height	Containment
Seal geometry – lateral continuity	Un-faulted	Laterally variable faults	Containment
Seal geometry – thickness	>100 m	<20 m	Containment
Hydraulic integrity: seal	Presence of mineral and stress characterization data of seal	Absence of mineral and stress characterization data of seal	Containment
Distance between CO_2 emissions source and target medium	<300 km	>300 km	Transportation cost

A reservoir screening map is created using the different criteria parameters mentioned above. Only the permeability and reservoir thickness are combined and introduced as ‘kh’ , in *Figure 6.2*, because it is believed that the well injectivity is affected by both parameters together as soon as the reservoir capacity is sufficient. In *Figure 6.1*, the suitable reservoir capacity is selected primarily according to the pore volume available for storage. Also, reservoir pressure and temperature are essential as they define the CO_2 phase in the reservoir, which in turn is preferred to be supercritical state, for many reasons mentioned in previous chapter, i.e., higher CO_2 density, better injectivity, and avoiding phase change during injection process. Furthermore, the injectivity and containment selection maps are represented *Figure 6.2* and *Figure 6.3*.

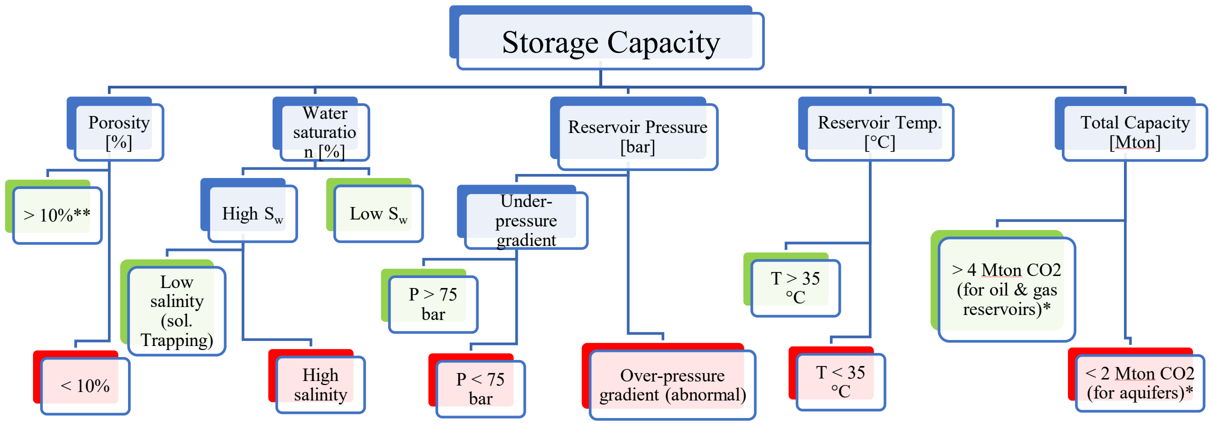


*Figure 6.1 Reservoir Storage capacity screening map (suitable conditions are in green, while the reds are the unsuitable). *After Ramirez et al. 2010 (the threshold capacity can be changed according to CO_2 source capacity), **Higher porosity is favored for higher storage capacity and better injectivity.*

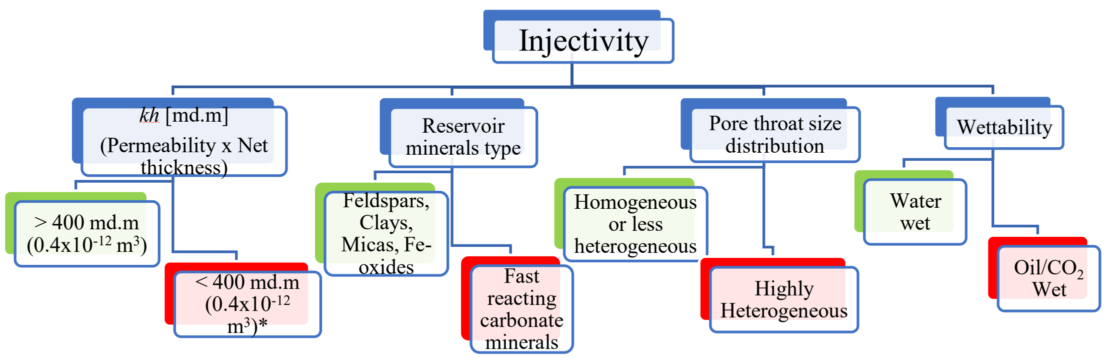


Figure 6.2 Reservoir injectivity screening map (suitable conditions are in green, while the reds are the unsuitable). The threshold value of (kh) can be changed according to the number of injection wells and the daily injection rate.*

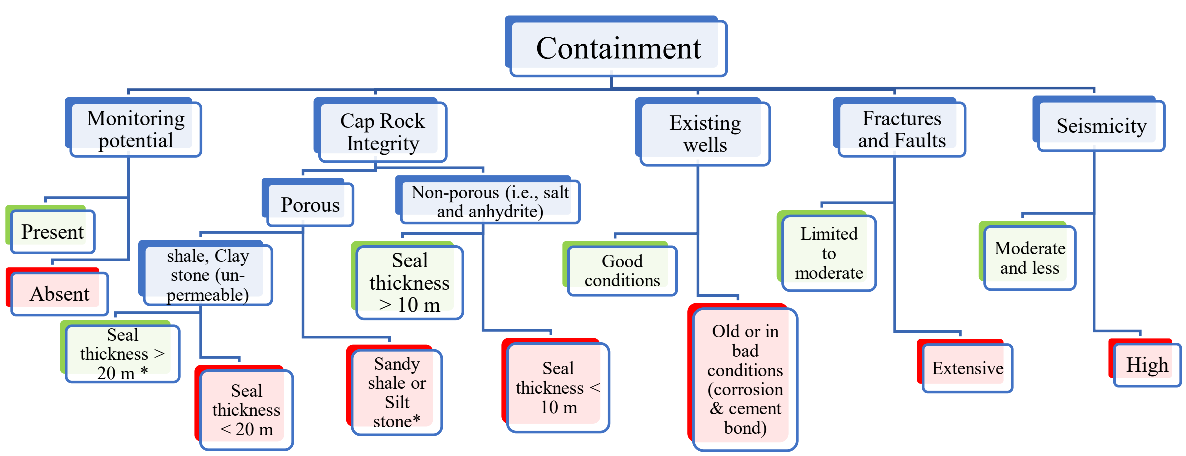


*Figure 6.3 Reservoir Containment screening map (suitable conditions are in green, while the reds are the unsuitable). *Capillary containment to be verified.*

6.2. Site Selection

The site selection process is used to further evaluate the suitable candidate reservoirs and to develop a short list of highest potential sites for deeper characterization. Site selection uses and validates the existing data and analyses from the site screening and supplements them with additional information or other purchased data to evaluate the characteristics of the selected sites. Then, the logical sequence of ranking the candidates, *Figure 6.4*, and refining the selection parameters till the best candidate is reached.*(Alcalde et al., 2021)* This phase corresponds to the second project status of a typical oil exploration program that involves the evaluation of the technical and non-technical components, i.e., subsurface geologic data, regulatory requirements, model data, site data, and social data, represented in *Figure 6.5. (NETL, 2017)*

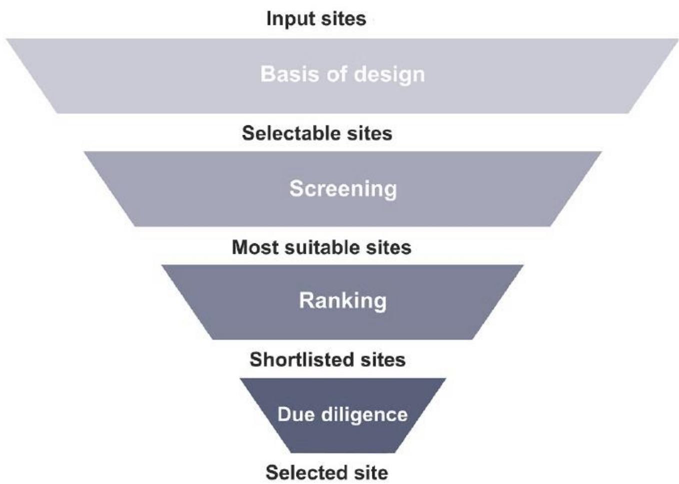


Figure 6.4 Overview of the site selection workflow to select the most suitable site.(Bentham et al., 2014)

After a deep investigation in the screening criteria that were introduced recently to find the optimum methodology for selecting the candidate storage reservoirs for GREEN1, a new logic maps were introduced to help the analyst make the right decision. The maps are divided into three main categories explained above: storage capacity, injectivity, and containment (Figure 6.1, Figure 6.2, and Figure 6.3), each category includes the relevant parameters for selection. The selection of the right candidate is seriously crucial for the whole project life including the design of all the surface facilities up to post-injection monitoring and HSE regulations.

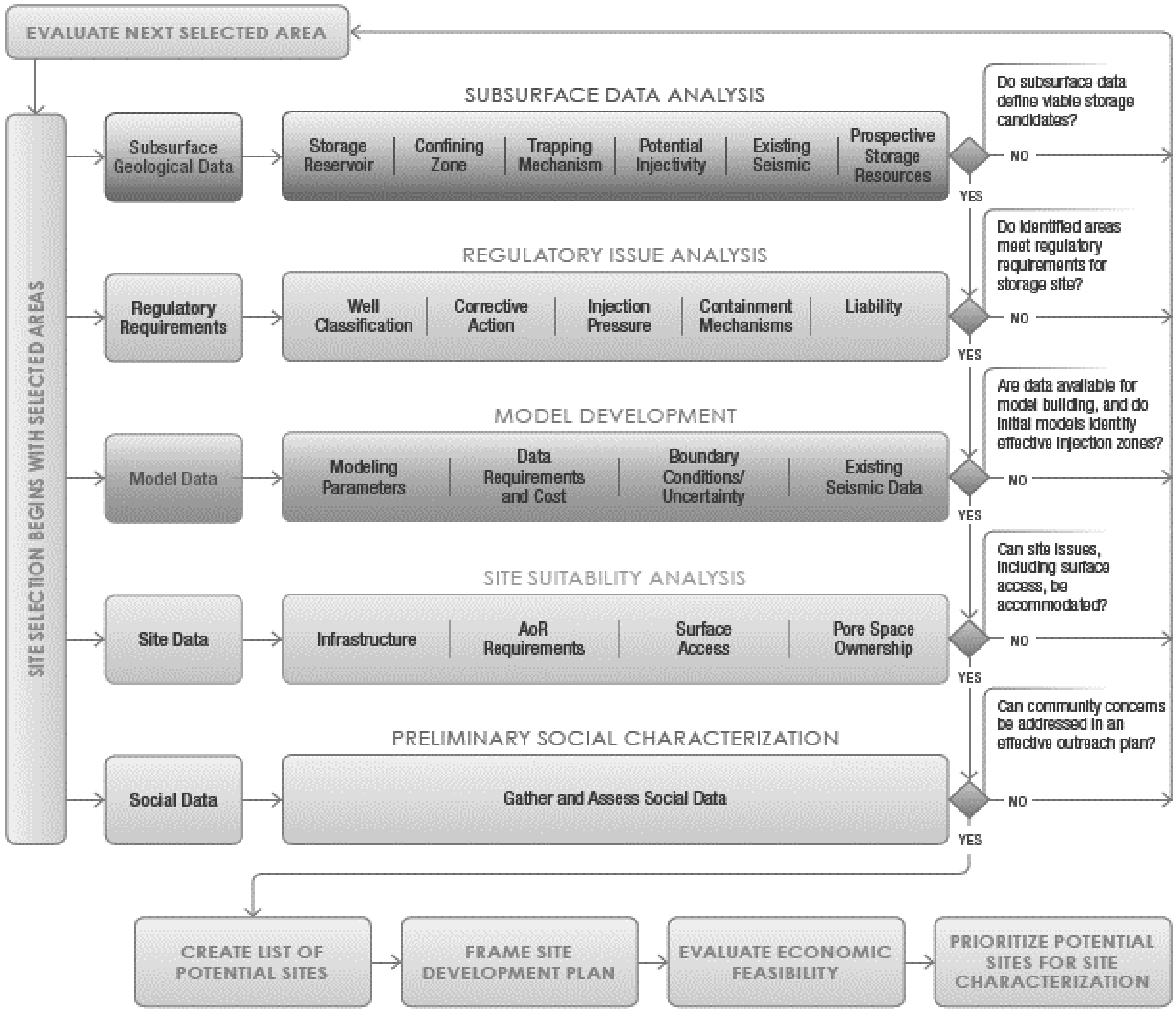


Figure 6.5 Process Flowchart for Site Selection.(NETL, 2017)

Conclusions

Unlike fluid and structure mechanics, the performance of underground rocks and fluids of a porous media is hardly predictable. Every single reservoir behavior is unique, even within the same layer there are lots of heterogeneities. Each part of a reservoir has its own porosity, permeability, and stresses, with different rock-fluid interactions than the other. A good reservoir model can't be achieved without performing the adequate tests and simulations to obtain all the parameters that shall characterize the storage process. Nevertheless, the understanding of these parameters and their correlations with the design of the surface facilities is the key to a successful underground carbon storage project.

In CCS, the design of all the upstream components is mainly based on the reservoir parameters. For example, the transportation pipeline diameter, compression capacity, and maximum allowable pressure are defined according to the injectivity, that can be represented by reservoir pressure, permeability and thickness (*kh*). Additionally, a wide range of injection rate should be considered during the design to cope with the rate drop due to the gradual reservoir pressure increase. Moreover, storage capacity has a vital role in the reservoir screening process, accompanied by an economic feasibility study. The calculated CO_2 storage capacity of 'Porto Corsini Mare' reservoir (2.1 Mton), as a candidate site for GREEN1, was estimated based on returning the depleted reservoir to its initial pressure before production. Above all, a successful GREEN1 conversion design can be achieved by considering the following points:

- The transportation and injection of CO_2 in supercritical phase is preferred due to its high density and low viscosity, thus, better injectivity.
- Expecting gradual increase in WHP during the first days of injection, until the reservoir boundaries are reached. Then, due to slow reservoir pressure increase, the pressure build-up rate is much lower after reaching the boundaries. To mitigate the WHP increase, it should be accompanied by rate reduction not to pass the pressure limit.
- A wide range of injection rate is mandatory during the design of the pipeline and compression facilities, so that they would be able to cope with the gradual reservoir pressure increase throughout the injection period.
- Close monitoring to WHP and WHT with adequate emergency shutdown systems to avoid the risk of reservoir or cap rock fracturing during the injection process and assure CO_2 containment within the target formation.
- The variation of the ambient temperature for the land and underwater pipeline through the year, and the geothermal gradient for the injection well, as it might have a serious effect on the CO_2 phase behavior. Therefore, thermal isolation or additional heating and compression station may be considered.
- The risk of hydrate formation through the pipelines should be studied, especially at the regulation valve points, to void pipe plugging.
- If possible, Formation Integrity Test (FIT) should be performed prior to the CO_2 injection process to assure the integrity of reservoir formation, as the in-situ stresses might have been changed due to reservoir depletion at the production time.

- Not only computational simulations should be done to confirm the compatibility of the injected CO_2 with the reservoir fluids, but also core analysis in the lab should be done to check the long-term interactions between CO_2 and reservoir & cap rock.
- The residual gas in a depleted reservoir might reduce the CO_2 storage capacity, due to the expansion of the plume volume as a result of the low density of CO_2-CH_4 mixture. Nevertheless, it can be extracted by a good CO_2 EGR plan and appropriate injector/producer well distribution pattern within the reservoir.
- If the reservoir pressure and temperature values are near the CO_2 critical pressure and temperature, it is preferred to have highly pure CO_2 injection stream to avoid the transformation of the injected CO_2 to liquid phase inside the reservoir, which in turn would have negative effects on the fluid injectivity. However, after a sufficient increase in reservoir pressure, it is possible to have a less pure CO_2 stream.
- Establishing an accurate monitoring baseline in offshore environment require the understanding of not only current marine nature, but the possible future anthropogenic activities in the area also should be considered. That might require smaller spatial distance between detectors and/or higher recording frequency.

Most of these points, mentioned above, have been already considered during the design of GREEN1 project. A wide range of injection pressure to cope with the evolution of reservoir pressure increase is reviewed with WHP (48.5 – 68 bar) & BHP (79 – 145 bar) and injection rate 16.5 kg/s, and WHT (50 °C) & BHT (42 °C), keeping CO_2 in super critical phase.*(Pertuso, under preparation)*

Furthermore, this study Introduces a solid methodology for comparing and selecting the suitable reservoirs for CO_2 geo-storage as a part of CCUS chain, for the purpose of identifying the optimum storage site for GREEN1 platform. The introduced screening criterion is divided to three main categories: storage capacity, injectivity, and containment, with the relevant parameters to each category. The use of depleted oil & gas reservoirs has the privilege of reservoir model availability and assurance of containment.

Finally, logic maps were created to help the analysts and decision makers to easily identify and compare candidate sites for CO_2 storage, so that they are able to exclude the unsuitable reservoirs and proceed with the right candidates for economic and risk assessment studies.

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