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A Toolkit Approach for Carbon Capture and Storage in Offshore Depleted Gas Field

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Abstract: Fossil fuels are considered a dependable, cost-effective, and efficient energy source and their utilization has resulted in tremendous growth for humanity. However, it has its downside also. Experts are of the view that present energy systems are unsustainable due to their detrimental impacts on the environment. Oil and gas producers are charged that their infrastructure, utilization of materials and technologies for exploration, development, and operation, and production and consumption based GHG emission is harming the environment severely. Current atmospheric CO_2 concentrations are slightly more than 400 ppm, almost double since the beginning of the industrial revolution. CO_2 concentration is continuously increasing in the atmosphere which is causing an increase in the atmospheric temperature. Studies suggest that if no new emissions occur, even though the temperature would be 1.1°C higher at the end of the century due to significant accumulated CO_2 in the atmosphere. Is opined by some experts that a further increase of CO_2 concentration in the atmosphere would saturate its impact in terms of increasing trend of temperature rather it would be logarithmic in nature which means additional CO_2 concentration in the atmosphere would not increase the temperature alarmingly. However, IPCC suggested that the relationship is more linear and if CO_2 emission is not controlled then its effect would not just be worse but speed up the detrimental effects. Various measures are being taken up to reduce the CO_2 concentration in the atmosphere for preventing major climate change and control the detrimental side effects like natural calamities such as drought, flood, forest fires, and acidification of the ocean. CO_2 Capture and Storage (CCS) is one of the most important efforts in the spectrum of measures being considered and applied for managing this menace and meeting the net zero CO_2 emission target set by countries and companies by 2050. Development and adoption of renewable energy are gaining momentum, but it will take some time before renewable energy plays a dominant role in the total energy mix. Natural gas will play a transition fuel role before achieving the dominant role of renewable energy in the total energy mix and CCS will enable the development of contaminated gas fields to meet the gas demand. The world focus is on renewable and environment-friendly energy development e.g., solar, wind and hydrogen, etc. Carbon dioxide (CO_2) capture, utilization, and storage is the best option for mitigating atmospheric emissions of CO_2 and thereby controlling the greenhouse gas concentrations in the atmosphere. Despite the benefits, there have been a limited number of projects solely for CO_2 sequestration being implemented. The industry is well-versed in gas injection in reservoir formation for pressure maintenance and improving oil recovery. However, there are striking differences between the injection of CO_2 into depleted hydrocarbon reservoirs and the engineered storage of CO_2. The differences and challenges are compounded when the storage site is karstified carbonate in offshore and bulk storage volume. It is paramount to know upfront that CO_2 can be stored at a potential storage site and demonstrate that the site can meet the required storage performance safety criteria. Comprehensive screening for site selection has been carried out for suitable CO_2 storage sites in offshore Sarawak, Malaysia using geographical, geological, geophysical, geomechanical, and reservoir engineering data and techniques for evaluating storage volume, container architecture, pressure, and temperature conditions. The site-specific input data are integrated into static and dynamic models for characterization and generating performance scenarios of the site. In addition, the geochemical interaction of CO_2 with reservoir rock has been studied to understand possible changes that may occur during/after injection and their impact on injection processes/mechanisms. Novel 3-way coupled modeling of dynamic-geochemistry-geomechanics processes was carried out to study long-term dynamic behavior and the fate of CO_2 in the formation. The 3-way coupled modeling helped to understand the likely state of the injectant in the future and the storage mechanism, i.e., structural, solubility, residual, and mineralized trapping. It also provided realistic storage capacity estimation, incorporating reservoir compaction and porosity/permeability changes. The study indicates deficient localized plastic shear strain in overburden flank fault whilst all the other flaws remained stable. The potential threat of leakage is minimal as the target injection pressure is set at initial reservoir pressure, which is much lower than cap rock breaching pressure during injection. Furthermore, it was found that the geochemical reaction impact is shallow and localized at the top of the reservoir, making the storage safe in the long term. The integrity of existing wells was evaluated for potential leakage and planned for a proper mitigation plan. Comprehensive Measurement, Monitoring, and Verification (MMV) were also designed using state-of-art tools and dynamic simulation results. The understanding gaps are closed with additional technical work to improve technologies application and decrease uncertainties. A comprehensive study for offshore CO_2 storage projects identifying critical impacting elements is crucial for the estimation, injection, containment, and monitoring of CO_2 plumes. The information and workflow may be adopted to evaluate other CO_2 projects in both carbonate and clastic reservoirs for long-term problem-free storage of greenhouse gas worldwide.

Keywords: Contaminated Gas Field, CO_2, Storage, Capacity, Containment Coupled Geomechanics, MMV

Introduction

Fossil fuels are considered a dependable, cost-effective, and efficient energy source, facilitating transport and industrial production, and resulting in development worldwide. Consumption of energy is much higher in developed countries compared to developing countries. A sizeable percentage of the population in countries with lower consumption of energy are leading subjugated life. Experts are of the view that present energy systems are causing unsustainable development and creating an imbalance in the environment. Oil and gas producers are charged that they are harming the environment in a big way. This is not an incorrect accusation. The gamut of activities in the oil and gas industry consumes a lot of energy for the final production of oil and gas and value-added products, including refining. It includes the requirement of huge steel, cement, drilling, and completion machinery and fluids, drilling processes, chemicals, and processing activities. Thus, every action requires enormous energy, which produces CO_2. When fossil fuels are consumed in industry and transport, residential places, refining also produces GHG making oil and gas a significant source of GHG emissions Fig. 1.

Additionally, there are gas fields that have a high percentage of CO_2 and other contaminants. Gas production from such fields contributes to GHG emissions after processing. Further, if the gas market is unavailable and oilfields are in far-flung areas, processed hydrocarbon gas is also vented into the atmosphere. Thus, Greenhouse Gas (GHG) emissions are increasing continuously worldwide and causing the climate out of balance. One of the most significant contributors to GHG is CO_2. Carbon dioxide is present in the atmosphere in a small percentage and plays an important part in the life cycle of living beings and vegetation. It is made of carbon and oxygen atoms and is a very stable molecule. Physical property wise CO_2 is a colorless and odorless gas. It is exhaled by living beings and used by plants in photosynthesis. Small concentration is not a problem. But it can cause asphyxiation at higher concentrations. CO_2 is denser than air therefore its concentration would be higher in low-lying and in poor ventilation areas.

CO_2 concentration was around 280 ppm during preindustrial time which has increased to a level of 412 ppm. This is a significant increase. CO_2 gas has the property to absorb infrared radiation from the sun and heat up the atmosphere. This is one of the contributors to global warming. However, the presence of water vapor and methane gas also contributes to warming. Methane has a high capacity to heat up the atmosphere, but its half-life is less, so it is not a cause for concern. However, the venting and flaring of methane gas by the oil and gas industry are being controlled. An increase in temperature makes the earth's system out of balance. This phenomenon brings more energy flowing into the system than flowing back out of the earth system. Earth's system contains nearly seventy-five percent water in the oceans and specific heat water is also higher compared to land mass and vegetation, so they absorb the excess energy. Water cools the air at the surface but over time this increased temperature may heat up the deeper portion of the oceans which will result in an overall increase in atmospheric temperature.

Studies suggest that if no new emissions occur, even though the temperature would be 1.1°C higher at the end of the century due to significant accumulated CO_2 in the atmosphere. Is opined by some experts that a further increase of CO_2 concentration in the atmosphere would saturate its impact in terms of increasing trend of temperature rather it would be logarithmic in nature which means additional CO_2 concentration in the atmosphere would not increase the temperature alarmingly. However, IPCC suggested that the relationship is more linear and if CO_2 emission is not controlled then its effect would not just be worse but speed up the detrimental effects.

The following four factors could work together to speed up the warming of the atmosphere:

- Rapid economic growth: Worldwide development is lopsided. Less developed countries are making efforts for faster development to ameliorate poverty and increase the living standard of their population. The population is increasing. Urbanization also taking place at pace. To meet the industrialization energy requirement, more specifically power generation would increase. Increased industrial growth will bring mobility growth which will enhance the use of oil and gas. All these will contribute to GHG emission
- Past emissions: There is more than 400 ppm of CO_2 in the atmosphere and this has accumulated over a period of time Additionally, low-concentration methane is also present which is a stronger warming effect. Methane is vented in many isolated oil fields during processing and lacks its utilization in a techno-economic way. CO_2 will stay in the atmosphere until it is removed. However, methane will decay in 12 years' time. Cattle are also contributing to GHG emission
- Carbon sink situation: Ocean is the biggest sink for CO_2. More than 90% of CO_2 is absorbed by Ocean. Nearly 5 ppm of CO_2 is added every year and approximately 2.4 ppm of CO_2 is utilized by ocean, plants, and trees for photosynthesis. Thus, net addition every year is around 2.5 ppm. Deforestation will adversely affect this phenomenon and reduce CO_2 utilization by them. Ocean will also eventually saturate with CO_2 over time. The deeper part of the ocean will get warmer
- Committed warming: It means that existing CO_2 in the atmosphere will cause the temperature to rise even if CO_2 concentration stops increasing. The warming of the ocean has not kept pace with the warming of land due to its enormity. This is the reason for the delayed warming

Impact of CO_2 on Humans

We breathe CO_2 which is present in the air in a small percentage. It becomes dangerous for human health when its concentration becomes very high. Humans start feeling dizziness, nausea, and headache when CO_2 concentration is more than 50,000 ppm. Excessively high concentrations of CO_2 can cause death due to asphyxia as its higher concentration will reduce oxygen levels in the air. Leaked CO_2 generated due to the combustion process can disperse quickly in open areas. Dispersion is aided even with low wind. CO_2 concentration is observed in places that are way from the CO_2 source. Potential risk to the population due to CO_2 leakage is restricted to close environments and low-lying areas because CO_2 is dense and accumulated close to the topographically earth's depression surface. CO_2 eruption has been observed in Lake Nyos in Cameron and that has caused the death of more than 1500 people and 3000 livestock. In Italy at Ciampino, near Rome, houses are located only 30 m from gas vents, where CO_2 concentrations in the soil reach 90% and about 7 tons of CO_2 are released daily into the atmosphere. The local inhabitants take preventive measures to avoid any danger by practicing avoiding sleeping in the basement and maintaining proper ventilation in their houses.

Scientists and engineers are clear and well-informed about scientific aspects of CO_2 storage but the public's attitude, or acceptability, relates to the amount of knowledge it possesses about CCS. The main concerns in the eyes of the public revolve around the safety and reliability of storage of the CO_2. CO_2 eruption has happened in the past in Lake Nyos in Cameroon and around 1500 people and 3000 livestock have lost their

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lives. The presence of mercury in marine fish has also been found in Southeast Asian countries in various concentrations. Therefore, public acceptability becomes paramount without which it would be difficult for the project to proceed. Energy industry professionals along with media and NGOs should propagate awareness among the masses about the stability of CO_2 storage in the subsurface for a long period and the impact of the earthquake and micro seismic activities considered in the study. The legal, regulatory frameworks and economics of the CCS are another challenge for CCS projects. This makes the role of governments more important and critical for suitable legislation and regulations. Governments should also absorb the additional cost of CCS which makes the green energy sources expensive.

Impact of CO_2 on the Environment

The impact of CO_2 on the ecosystem would vary depending on the location of the storage site. In the case of CO_2 storage offshore depleted oil and gas fields and saline aquifers would be different compared to storage sites onshore. In the former case, CO_2 may leak to the seabed and affect the pH which will become more acidic and impact the life of animals. This effect may be localized and would get rectified once the leakage is controlled. Land-based leakage would affect vegetation if not very high. This may work as fertilizer in the soil and increase crop productivity. However, higher concentrations may be lethal to living beings. This effect also may be localized and things would be as usual away from the leakage points.

In case CO_2 leakage takes place in potable water-bearing zones, pH may change and water may become acidic. Change in pH value would depend upon the concentration of the CO_2. If the concentration is not very high, then the effect would be marginal. It has been seen in some cases water from aquifers enriched with CO_2 is sold as sparkling mineral water. In some geological and hydrogeological structures, the acidification of groundwater can result in rock dissolution, decreased structural integrity, and the formation of sinkholes.

Decarbonization and Natural Gas as Transition Fuel

The world plans to move for utilization of greener energy which is environment friendly. However, fossil fuels will remain a significant energy source in the near future because of a growing population, urbanization, development, and lack of adequate renewable energy resources to meet the demand and work with existing technologies. Therefore, natural gas will play the role of transition fuel. Conventional sweet gas reservoirs are getting exhausted. Now more discoveries in hostile environments, deep and ultra-deep water, unconventional shale, and CBM reservoir are getting focused. Additionally, contaminated natural gas reservoirs that were on hold or on limited production are being considered for development and production to meet the supply gap. Natural gas reservoirs that contain impurities such as CO_2 and H_2S need to be separated before the gas can be transported by pipelines or liquefied into LNG to meet the user specifications, which are generally less than 6.5% and 20 ppm, respectively. The separation process results in a very concentrated stream of CO_2. It increases the concentration of H_2S, which is easy to transport and store, making this one of the easiest and lowest-cost applications of CCS. Thus, CCS helps to commercialize stranded high CO_2 gas fields where CO_2 concentration rates can be as high as 50-70%. Development and management of such contaminated gas fields become more challenging when they are located offshore. This study describes the development of a giant offshore carbonate gas field that holds more than 10 Tcf of contaminated gas in a 1000 m gas column. The field contains 20-25% of CO_2 and around 100 ppm H_2S. The second part of the study includes separating contaminants and transporting the supercritical/liquid CO_2 for safe storage in a multi-layered depleted carbonate gas field. The study also briefly discusses the initial feasibility of the utilization of CO_2 invaluable products. Limited understanding is available in the industry for bulk storage of CO_2 in an offshore environment in depleted gas fields. It becomes essential to develop processes and procedures for carrying out successful CCS projects.

The toolkit we are discussing will help design the CCS project for the oil and gas industry offshore and explain various steps. Our objective for the CCS toolkit is to meet the following broader goals:

- Step-by-step process descriptions for CCS to protect the environment
- Things to be done during planning, execution, and post operation
- Protect human health and safety
- Protect underground sources of drinking water and other natural resources
- Comply with regulations for emission reduction and ensure their confidence in proper GHG accounting
- Timely deployment and cost-effectiveness of technologies

Field Development Plan (FDP) Linked with CCS Storage Development Plan (SDP)

The source field under discussion, located in Offshore Malaysia is an isolated pinnacle carbonate reef build-up with an area coverage of 5 × 3 km at gas-water contact. Depositional facies indicate a series of pro-gradational/retro-gradational processes. The gas column thickness is estimated to be 986 m, i.e., from crest to the depth of free water level holding around 10 Tscf gas in place. Overall, reservoir quality is well developed in the center of the field compared to the flank area. The reservoir quality starts deteriorating from mid to the bottom of the pinnacle reef based on porosity and permeability. Pressure variation from top to bottom is significant due to the thick gas-bearing column. MDT pressure points suggest gradients for gas and water as 0.107 and 0.43 psi/ft respectively and FWL at 3035 m TVDss which is also supported by logs. The initial reservoir pressure is approximately 5940 psi at a datum depth of 3035 m TVDss with the aquifer being over-pressured by 1600 psia. Temperature data obtained with DST and MDT in exploratory and appraisal wells show significant differences. This difference is due to the mud cooling effect in MDT, hence temperature measurement from DST was considered more reliable and representative to be used in facilities design. Significant temperature variation was observed on bottom hole temperature measurements from both wells. DST operation conducted in well-1 was approximately 500 m shallower than in well-2. However, temperature measurement from well-1 DST is higher than well-2 but closer and within the regional DST cloud temperature. Well-1 DST point was used to estimate representative bottom hole temperature for the field. The temperature gradient of 4.6°C/100 m at reservoir datum depth 3035 m TVDss gives a reservoir temperature of 180°C/356°F.

FDP is an important strategic document of oil and gas companies. Investment decisions are made based on this document. FDP is a process of creating a new or modifying the existing development plan for necessary operating procedures for production, mid-course correction, reservoir management and surveillance, processing, storage, and delivery of oil and gas. This must be efficient, economical, and optimal. A key component in Field Development Plan (FDP) is making predictions for future field performance, in terms of oil and gas flow rates, injection rates, and ultimate recovery. In the case of the source field, it is prepared with limited data and thus carries various degrees of uncertainties and risks. FDP is continuously updated with the availability of more data but still requires focus to avoid the unwanted. A reservoir model is a 3D digital representation of a hydrocarbon reservoir that is built utilizing available G&G, rock, and fluid data and updated as new data is available and used to support the ongoing life cycle needs of the field such as volumetric estimates, well planning, reservoir simulation, production forecasting and simulating the recovery processes and their mechanisms. The idea is to have a model which is close to reality but many times limited data and their quality limit the quality of model description and definitions. The resolution of data is another challenge in capturing the properties and their variations in the fields. This further limit the realism in achieving and understanding the description of the field/reservoir. The said reservoir is complex in its geometry as well as in the variability of rock and fluid properties contained in it. There are various types of uncertainties associated with all these data at every stage of field life. They could be in terms of limited data, quality of data, resolution of tools used for measurement, and incorrect interpretation of data. These data are acquired at a smaller scale and are scaled up to the field level. Scaling up also introduces additional uncertainties in the system. There are known knowns, known unknowns, and unknown unknowns in the reservoir. The degree may vary from reservoir to reservoir and field to field. The incorporation of dynamic data brings reliability to the static description/characterization of reservoirs and fields. The uncertainty level is high in green fields and relatively less in brown fields where the reliability of models is improved by incorporating the dynamic data viz pressure production history and acquiring more data and some diagnostic data during production history to capture the changes in parameters with time. Generally, uncertainty reduces with time, but deviations have been observed in actual production behaviors with respect to forecasts in the majority of the fields.

An exact solution to reservoir engineering problems is not possible due to the large size of reservoirs, the complex nature of fluid distribution in the porous media, and a number of influencing variables. Therefore, approximations are made to have possible solutions. Due to this limitation, the practice is to have a deterministic solution using average parameters. Scenario-based cases are generated to understand the minimum and maximum outcomes along with average values. This provides an idea of variations, but it is not the right way of doing things. All the minimum parameters in one case for the low outcome and similarly all the maximum parameters in another case for a higher value may not be a reality. We will be either overestimating or underestimating the outcomes. Therefore, it becomes important to understand the variations. If parameters are well described in the form of distribution functions, then outcomes also need to be generated in the form of distribution functions and be explained accordingly. This introduces the complexity of deriving solutions for reservoir engineering problems. Statistical techniques are used to resolve these points. Fluid flow in the porous medium is a complex phenomenon and a large number of parameters influence this.

All these parameters carry various degrees of uncertainty and cannot be given equal treatment as they will increase computing requirements drastically and delay the completion of the study. Therefore, parameters that have a significant impact can be identified and incorporated into the calculations. The principal feature in field development planning is decision problems under uncertainty. Offshore development has a greater amount of inherent uncertainty than onshore development because it is more difficult to obtain relevant information. An integrated FDP and Storage Development Plan (SDP) enables the development of contaminated gas fields. (Grenville Rowan, Ringrose, and Bentley).

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Storage Development Plan (SDP) comprises strategy, concept, and management of CO_2 storage in depleted oil and gas fields, saline aquifers, and coal seams. The primary goal of this study is to estimate the storage capacity, containment in the target fields/reservoirs. A systematically prepared comprehensive document incorporating all influencing parameters in reservoir characterization, including CO_2 phase behavior and other contaminants, overburden cap rocks, estimation of adequate storage volume of CO_2, injection rates, and injection duration within pressure limit so that cap rock is intact. After injection, CO_2 stays in the reservoir through four mechanisms: Hydrodynamic, solution trapping, residual trapping, and mineralization. The bulk of CO_2 storage is in the structural (hydrodynamic form). However, solution trapping, residual trapping, and mineralization enhance the storability and safety of CO_2 in the reservoir and prevent leakage. CO_2, being gas, moves in the reservoir due to buoyancy. Therefore, plume migration/movement in the reservoir is monitored. Measurement, Monitoring, and Verification (MMV) is equivalent to Reservoir Management and Surveillance in oil and gas field development and management.

There are some differences and commonalities between SDP and Field Development Plan (FDP). Reservoir Characterization is vital in both FDP and SDP. Overburden rock inclusion in the study becomes critically crucial in SDP compared to FDP. In the FDP forecast, pressure reduction occurs due to production, impacting production rates and volumes and ultimately the recovery from the fields. In SDP, pressure increases due to continuous injection of CO_2 and which may create problems like cap rock break, fault activation, the integrity of existing legacy wells, and facilitate leakage, which is not common in producing fields. In producing fields with a decline in pressure, compressibility, and stresses can cause compaction and subsidence. Compaction may help to improve the recovery, but subsidence may create operational challenges. Uncertainty in oil and gas-producing fields gets reduced with time as more data and information is acquired whereas uncertainty in CO_2 storage increase with time. Therefore, Reservoir Characterization becomes critical.

Due to the interaction between CO_2 and reservoir rocks, reservoir morphology, petro fabric, and associated properties may change. They may affect the overall storage process and mechanisms and therefore they need to be studied. These are the additional components in SDP compared to FDP. Geomechanics is crucial in highly compressible reservoirs in FDP, but this becomes more important in SDP for evaluating possible leakage through fault reactivation and cap rock breach. Hence, Geomechanics and Geochemistry are more important in SDP. Pressure maintenance is essential for higher oil recovery, whereas pressure management for creating the void space in the reservoir for storage is critical for CO_2 injection in a saline aquifer. Some problems like wellbore damage (skin) and solid movement within reservoirs due to production and injection can occur both during the production and injection phases. Another striking difference is that in FDP, after abandonment, the reservoir pressure is at the original or below the original reservoir pressure. Therefore, the chances of leakage due to pressure re-equilibrium are minimal. However, in SDP, the reservoir will be in pressurized condition for ages and therefore, pressure management and setting the target pressure for CO_2 injection is critical. Depleted fields with significant water encroachment would be better for storage than pure depletion reservoirs as residual and solubility trappings would be more pronounced and promote the stability of CO_2 storage.

An integrated Field Development Plan (FDP) and Storage Development Plan (SDP) provide answers to the following questions (Tewari and Sedaralit, 2021):

- How big is the contaminated gas field?
- How many wells will be required for maximizing the recovery?
- What is the plateau rate and plateau period?
- What would be the facilities required?
- Which carbon-capturing technology and facilities will be required optimally separate the contaminants?
- Minimization of uncertainty and risk
- Optimization of CAPEX and OPEX?
- How large is the structure for CO_2 storage?
- How is it distributed both are ally and with depth including overburden cap rock?
- How many wells will be required for injection in depleted reservoirs and producers and injectors in saline aquifers?
- What will be the production rate of water for creating the pressure sign in a saline aquifer?
- What will be the injection rate of CO_2 in supercritical and liquid forms?
- What will be the total volume injected?
- What will be the amount of storage in different forms?
- How will the reservoir (s) behave after injection in terms of pressure and plume migration?
- How will the CO_2 injection cause geochemical and geomechanical effects in the reservoir?
- How will the CO_2 plume migrate?
- What are the problems in applying the proposed methods of injection?
- What is the appropriate MMV to be incorporated?
- What facilities are necessary for injection? Are they available or must be created?
- What are the associated costs?
- What is likely field and facilities life?
- What political and/or economic factors are present that would influence the storage development?
- What information is available and what are the areas of uncertainty?

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Static Model of Contaminated Gas Field

A fine scale model for the source field has been prepared to account for the reservoir heterogeneity and then it has been up scaled to have a realistic run time in dynamic simulation. The reservoir model has been made to incorporate the Karst features which may influence the fluid flow in the reservoir. Low, most likely, and high cases of Karst distribution have been generated. Those scenarios were based on the uncertainty of vertical karst development as well as the horizontal karst development that can be linked to the major stratigraphic event in the region. GIIP estimation was done in deterministic and probabilistic methods based on the sensitivity range of porosity, permeability, fluid contact, Saturation (Sw), and formation volume factor (Bg). Formation volume factor variation is very critical in this case as the thickness of gas bearing column is around 1000 m. Porosity distribution in the model was carried out in two steps as background porosity model and the Karst porosity model. The accuracy of the Karst Model depends on the cell size that has been used in the static model. The cell size in the model should be in balance between capturing the closest evidence of Karst and the total cell numbers for history match/simulation purposes. The porosity Permeability transforms cross plot from core plugs data has been used to enhance the porosity permeability relationship in Fig. 1. The permeability from RCI is used to validate and calibrate the updated porosity and permeability relationship (Fig. 3).

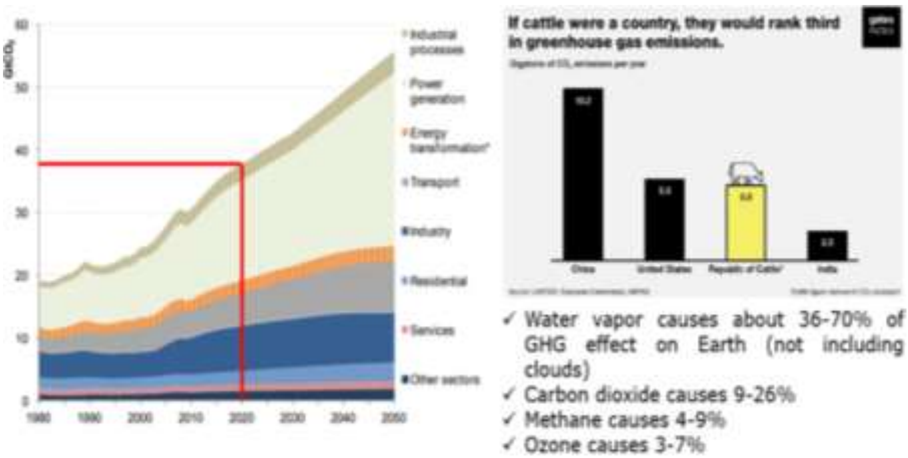

Fig. 1: GHG emission

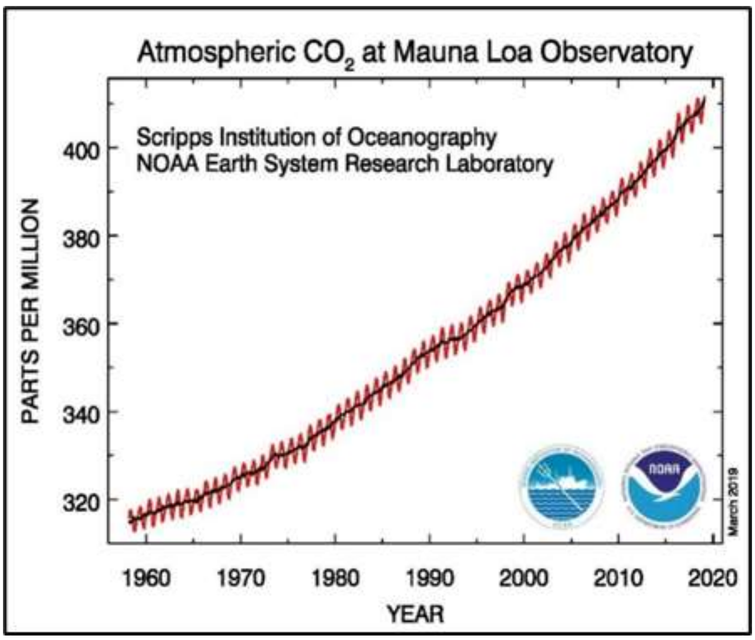

Fig. 2: CO_2 concentration rises in the atmosphere

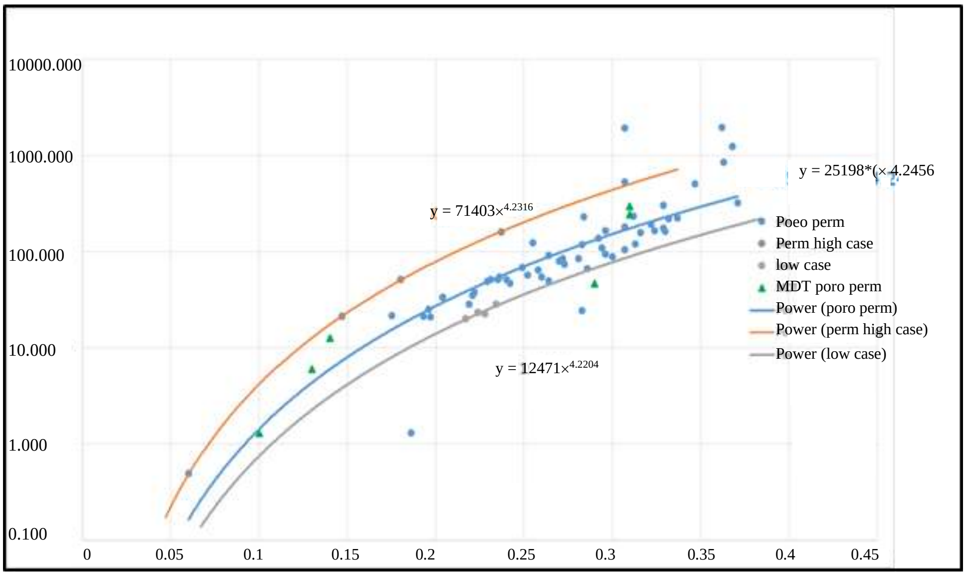

Fig. 3: Porosity and permeability cross plot

The deterministic estimate of GIIP is 10.013 Tcf which distributes between Karst Facies contributions and background facies as 1.332 and 8. 680 Tcf respectively. Probabilistic estimates of the GIIP in P90, P50, and P10 are 9.429, 10.087, and 10.806 Tcf respectively. Porosity is the biggest impacting parameter in the probabilistic estimate. The main objective of this task is to reduce the simulation running time by reducing the number of cells in the model. The coarsening was done for the vertical section (layer) (1690-600) whereas the lateral/horizontal cell size was kept as per fine scale static model (100 × 100 m).

Dynamic Modeling of Contaminated Gas Field

Refinement on the PVT model was performed, following revision made on reservoir datum depth and reference reservoir temperature at datum. PVT samples have a similar composition in both wells (Table 1). Therefore, reservoir fluid composition is assumed constant within the reservoir since no additional data is available to support possible compositional variation with depth, especially on the concentration of contaminants. 3-Parameter Peng Robinson Equation of State (EoS) was selected for fluid characterization analysis in the PVT simulator. A reasonable match on the estimated Z-factor at 356°F was achieved through regression analysis carried out on Omega-A and Volume Shift with a maximum error of 1.3%. The initial Condensate-Gas-Ratio (CGRi) estimated by the EoS PVT model is approximately 5.5 stb/MMscf. The presence of large quantities of Carbon Dioxide (CO_2) and hydrogen sulfide (H_2S) is characterized as an acid/sour gas system. This percentage of CO_2 could vary and in this field is around 20-22%. Acid gas forms acidic solutions when mixed with water.

Dynamic model was initialized at 58*44*1690 grids at fine scale which was upscaled to 58*44*755 grid cells. Grid dimensions are 100*100*0.8 to 100*100*1.5 m. Compressibility of the rock 5 × 10-6 psi-1 @ 5801.5 psia. Fetkovitch analytical aquifer model was used. A total gross gas production of 900 MMscf/day is expected to be produced from the proposed five gas producers (7" diameter). Gas production is constrained by tubing head pressure of 1160 psia. Reserves from deterministic simulation modeling are 4820 BScf and 7459 BScf at PSC life and end of field life respectively. The uncertainty analysis on subsurface uncertain parameters to evaluate the impact of fluid flow behavior and recoverable reserves using probabilistic modeling approach P90, P50, and P10 reserves ranging from 4575, 4562, 4723 Bscf and 7905,8062,8255 Bscf respectively. Vertical Permeability (PERMZ) was quantified as the most uncertain parameter which could either increase or decrease the forecasted recoverable reserves further. Relative permeability uncertainties were captured (Table 2). A scenario with six wells was also generated. Cumulative gas production forecasted which provides similar recovery. However, the plateau period for a gas production rate of 900 MMscf/d from 6 gas producers is prolonged by approximately three years, compared to the plateau period forecasted from 5 wells. (Fig. 4) Additional gas reserves can be recovered by lowering down tubing head pressure from an initial 80 to 40 bar.

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Table 1: CO_2 and other contaminants

DST fluid parameters	CGR, bbl/MMscf	CO_2, mol %	H2S, ppm	Mercury, ug/m3
Well-1	2.2	22	100-110	2.2
Well-2	1.7	19-20	95-100	0.15-0.32

Table 2: Range of relative permeability endpoints

Case	Sgr	Krwmax	Krgmax
Min	0.23	0.10	0.53
Base	0.27	0.26	0.96
Max	0.59	0.37	0.99

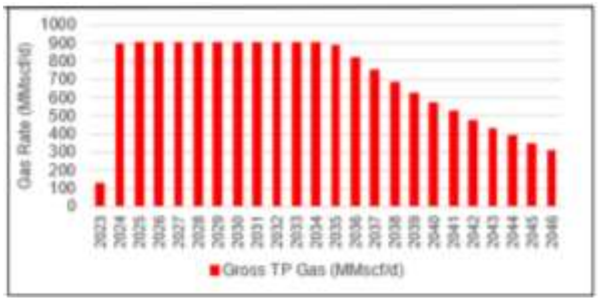


Fig. 4: Plateau rate of contaminated gas production

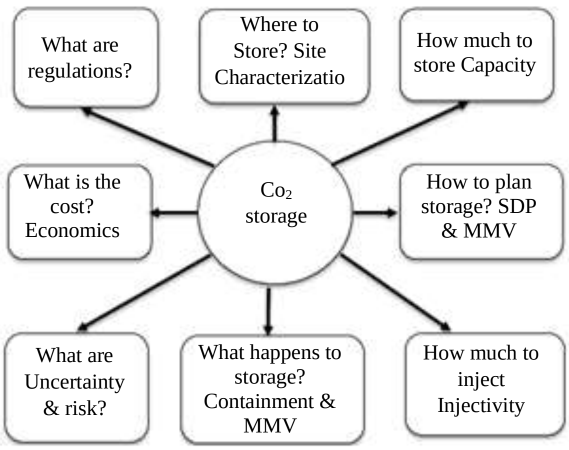


Fig. 5: What needs to be understood for CO_2 storage?

CO_2 Capture/Separation and Storage (CCS)

Amongst the spectrum of measures that need to be urgently implemented to mitigate climate change and ocean acidification, CO_2 Capture and Storage (CCS) can play a decisive role as it could contribute reduce roughly 33% of CO_2 reduction by 2050 (Rob Arts *et al*., 2008). It involves three main steps capture, capacity, and injectivity. CO_2 cannot be injected just anywhere underground as suitable host rock formations must be identified first. Site characterization is the most crucial step in ensuring the integrity of the storage project. Potential sites for geological storage exist throughout the world. The points shown in Fig. 5 need to be understood clearly and studied responsibly (Tewari *et al*., 2021).

CO_2 site must have sufficient capacity, containment, and injectivity. All these critical elements of CCS projects are described below for the selection of competent storage sites (Forbes *et al*., 2009; Raza *et al*., 2016; Teletzke and Lu, 2013; Das *et al*., 2021) Table 3.

Containment Analysis

Cap rock provides containment to stored CO_2 in the container. It is the most important criterion out of the three elements of capacity, containment, and injectivity in CCS site selection. The presence of cap rock/seal is identified during the screening of the storage site. The competent seal is a must in all storage sites viz. depleted oil and gas fields and saline aquifers. The existence of cap rock in depleted oil and gas fields is already established as it had retained hydrocarbon for millions of years. Changes in overburden properties need to be evaluated for compaction and subsidence happened during the production phase. Important parameters for a competent cap rock should be good thickness, lateral continuity, extremely poor porosity, and permeability which does not allow any fluid flow through it. CO_2 has a tendency to rise vertically upward in the reservoir due to the buoyancy effect and is obstructed/impeded by the impermeable seal on the top. Once this rise is stopped by seal then CO_2 spreads laterally. This trapping helps to increase the vertical column of the CO_2 which exerts pressure upward.

Most of the seals are shales, siltstone, evaporites, and fine-grained minerals comprising minimal interconnected pores. The petro fabric of cap rock makes them totally impervious in nature. It is observed that the lower part of cap rock which is in contact with CO_2 and brine gets affected because that will be in contact for a long period. Some reactions may take place which will result in the dissolution of minerals, and this will create a small effect on hydraulic and mechanical properties. The high injection pressure of CO_2 may create minor chemical and mechanical effects along faults and fractures. Therefore, a good seal must have no fractures and faults in the overburdened rock.

A good thickness of the seal will further ensure that no leakage takes place through it. In many storage sites, multiple seals are present as reservoirs are multi-layered. These layers have their own seals. The presence of multiple layers and seal provide additional security on two accounts; first CO_2 injected volume is distributed and each layers have its own injectivities and entry pressure in their respective overburden seals. This distributed CO_2 in multiple layers reduces the CO_2 escape from the intervals. Detailed reservoir characterization of the storage site becomes paramount. This can be performed with extensive geological, geophysical, and petrophysical data. The mineralogical analysis is useful in understanding the reaction of CO_2 with various minerals in the presence of water.

Table 3: Screening criteria for storage site

Sl	Parameters	Storage suitability go	Storage suitability no go
1	Depth for formation	800-2500 m	<800-2500 mor >
2	Porosity	>10%	<10%
3	Thickness net	>20 m	<20 m
4	Permeability	>10 mD	<10 mD
5	Formation water salinity	>30,000 ppm	< 30000 ppm
6	Rock-type	Quartz rich sandstone and carbonate	Highly stressed sensitive carbonates
7	Type of minerals	Minimal reactive minerals	Fast reactive minerals
8	Residual gas/waterless	high	
9	Hydraulic integrity	Less compaction	High compaction
10	Wettability	Strong water wet	Less water wet
11	Reservoir heterogeneity	less	high
12	Gravity number	less	high
13	Pressure at the start of injection	Normal or under pressure	Overpressure
14	Formation temperature	>35°C	< 35°C
15	Reservoir continuity	Unfaulted	Faulted
16	Caprock thickness and integrity	>100 m and good seal, capillary entry pressure much higher than CO_2 column top buoyancy pressure	<20 m and poor seal, capillary entry pressure is similar to buoyancy pressure
17	Wells	Good completions and away from fault	Poor completions and close to fault
18	CO_2 Density	High	Low
19	Interfacial tension	High	Low
20	Distance between CO_2 source and storage	Less distance has advantage	Large distance not preferred

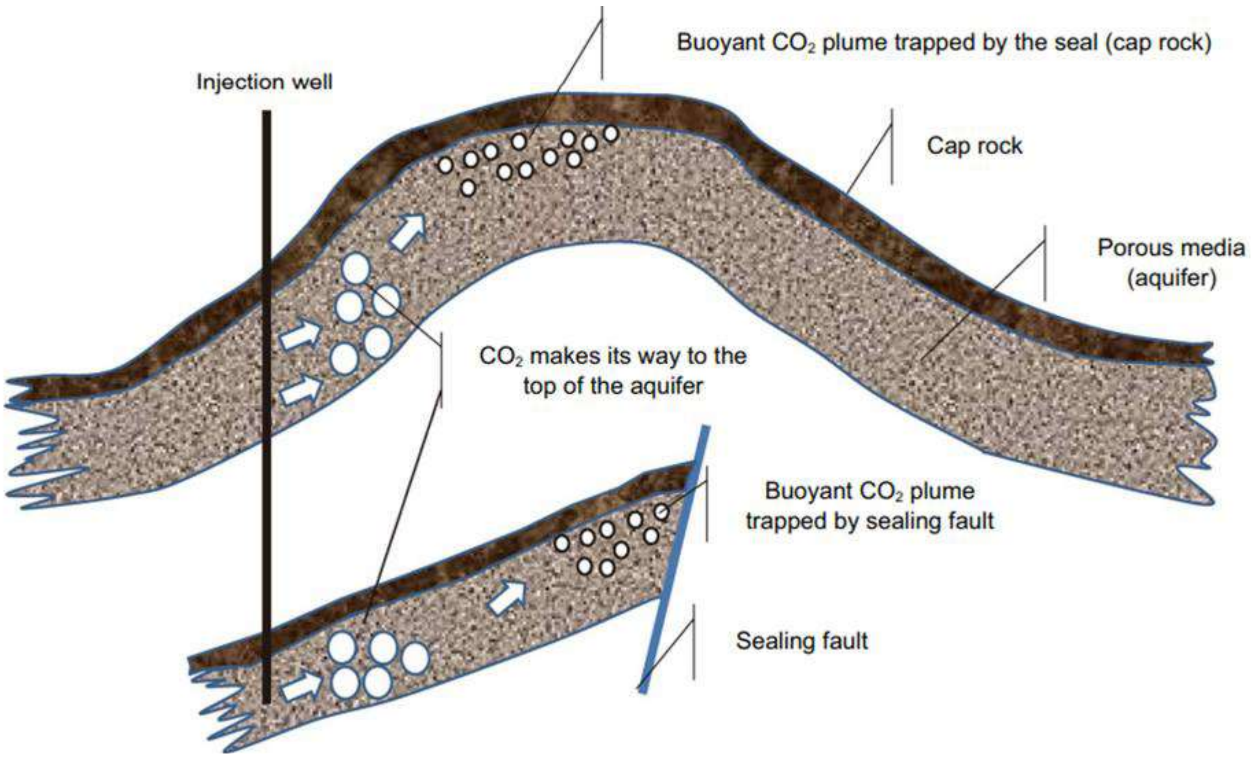


Fig. 6: Seal in storage formation

In most cases, no core data is acquired in shale or cap rocks. Drilling cuttings are very useful in this type of scenario. Capillary entry pressure on cap rock samples must be determined in the laboratory using Mercury Injection Capillary Pressure (MICP). MICP provides data for the pore size distribution of cap rock. The diffusion of CO_2 on core samples is measured in the lab. Interfacial Tension (IFT) and wettability of cap rock in the presence of CO_2 and reservoir fluids are also measured. CO_2 and seal interaction must be studied for understanding the safe pressure margin for storage. To ensure the safe injection and containment of CO_2 and avoid any unexpected failure of faults and fractures CO_2

injection pressure is carefully selected and the target of maximum pressure is set accordingly. In most cases, injection is planned to the original reservoir pressure conditions. In cases where faults and fractures are absent, a fracture pressure limit that is higher than the initial reservoir pressure can be considered. The pressure increase in the reservoir is monitored periodically. Important monitoring parameters are pressure and temperature measurement downhole, diagnostic logs in observation wells, time-lapse seismic survey, and CO_2 concentration measurement at the seabed as leakage through faults or fracture networks can be rapid and catastrophic. Results of comprehensive geomechanical and geochemical studies carried out for ensuring the safe storage of injected CO_2. Simultaneous injection and production can cause geomechanical deformation resulting in micro-seismic events (Fig. 6).

Data required for understanding and evaluating the containment are as follows:

- Regional geology
- 3D seismic data
- Petrophysical data (Ø, K, saturation, and thickness)
- Legacy wells and their drilling records
- Cement bond analysis of existing wells
- P&A status of exploratory and appraisal wells
- Stratigraphic analysis
- Structural analysis
- Core analysis
- Pressure production history in depleted fields
- In-situ stresses
- Rock mechanical properties
- Reservoir model
- Fault seal analysis
- Mohr-Coulomb failure analysis
- Numerical simulation incorporating geomechanics and geochemistry

A good seal must contain the following characteristics:

- It must be large, laterally continuous, and coverage over the reservoir, low vertical permeability, high capillary entry pressure, and sufficient thickness to trap the CO_2.
- Unfaulted, good thickness >10-20m
- Seal composition must be shale or claystone, salt, anhydrite
- The low density of legacy wells, good completion conditions and away from the faults, the sufficient margin between initial and fracture pressure
- The field under consideration for storage is a depleted offshore gas field. The field has a very good overburden seal with a thickness of more than 100 m. It has been thoroughly analysed for its suitability using coupled geochemical and geomechanical simulation

Fracture and Lithostatic Pressure

- CO_2 injection contributes a partial pressure in addition to existing pore fluid pressure
- Exceeding fracture/lithostatic pressure can open pathways (Fig. 7)
- Reactive faults (Shear failure)
- Newly created tensile cracks (hydraulic failure)
- Need to understand rock strength (fracture pressure) and lithostatic gradient

Capacity Estimation

Several parameters are used to generate the capacity estimates of which pore volume is the most important. Adequate pore volume will store the CO_2. Depth of the formation, area of injection, lateral extent, heterogeneity, compaction and subsidence of the formation, pressure limit for injection, storable pore volume, and trapping mechanism are critical in storage site evaluation. The following data helps to estimate the storage volume:

- Core analysis
- Petrophysical logs
- 3D seismic data
- Structure maps
- Structural and stratigraphic analysis
- Reservoir models (static and dynamic)
- Volumetric calculation
- Numerical simulation
- Geomechanics and geochemistry coupled simulation
- Thermal effect simulation of supercritical CO_2
- Low, most likely, and high-case scenarios of storage
- Sandstone or carbonate oil and gas-depleted reservoirs, Saline aquifers
- Over-pressured reservoirs excluded
- Compaction in the reservoir is not preferred
- Strong aquifer support is not good
- Depth 1000-2500 m
- Porosity >15% and Permeability >100 mD
- Thickness >50 m
- Low residual hydrocarbons
- Less heterogeneous
- Formation salinity is not very high
- Gravity number less
- Low reservoir pressure at the time of injection but more the critical pressure of CO_2

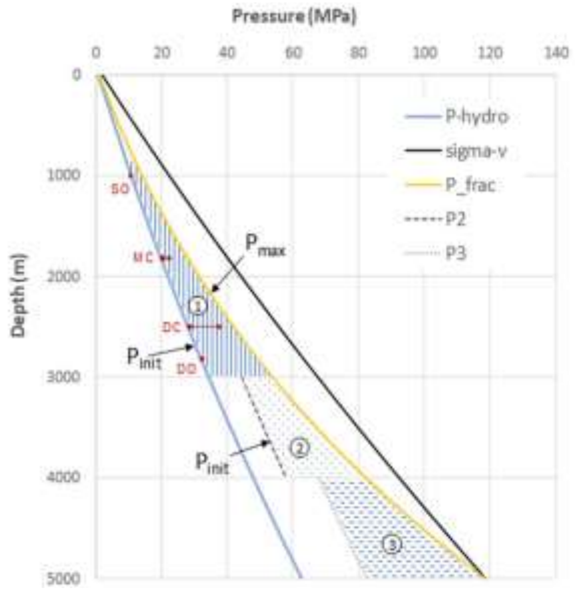


Fig. 7: Lithostatic pressure gradient

The following methods are used for the estimation of storage volumes of CO_2:

- Analog-based estimates of storable quantities require an analogous, mature storage project that includes the subsurface and surface components of the project. The project should have stored CO_2 and data to make a reasonable projection of storable quantities that is adequate to build an analog. Simple ratios may be used to scale storable quantities from the analog project to the project being assessed
- The volumetric method estimates storable quantities based on the pore volume ($A \times h \times \varphi$) of the geologic formation (s) and a storage efficiency coefficient (E). Due to the limited data required for the volumetric method; it is often applied at an early stage of a project:

$$M\,CO_2 = A \times h \times \phi \times \rho CO_2 \times E$$

where:

- MCO_2 is the mass of CO_2
- A is the area of the geologic formation considered for storage
- h is the average net thickness of the geologic formation. Total thickness may be used if E accounts for the net-to-gross thickness ration
- φ are the average effective porosity of the reservoir rock. Total porosity may be used if E accounts for the ratio of effective to total porosity
- ρCO_2 is the density of CO_2 at the average pressure and temperature of the portion of a geologic formation project to store CO_2

Estimates of storable quantities should consider CO_2 plume and pressure footprints that might adversely affect the storable quantities estimate. When pressure buildup is expected (e.g., in a closed system), the following equation may be used:

$$M\,CO_2 = A \times h \times \phi \times \rho CO_2 \times Ct \times \Delta P$$

where:

- Ct is the total compressibility
- Δp is the average pressure increase resulting from the stored CO_2

These equations will provide a low estimate of storable quantities because there is no fluid movement out of the geologic formation during the active injection. ΔP is likely to be depth-dependent, as rock stress is depth dependent and may be constrained by the risk of inducing seismicity.

The general equation for CO_2 storage resources in an aquifer is written as:

$$M_{Co_2} = A \times h \times \phi \times \rho Co_2 \times Es$$

Es is defined as follows:

$$Es = E_{An/At}\ X\ E_{hn/hg} \times E_{\phi e/\phi t} \times E_v \times E_d$$

- Net-to-total area ($E_{An/At}$)
- Net-to-gross thickness ($E_{hn/hg}$)
- Effective-to-total porosity ($E_{\phi e/\phi t}$)
- The volumetric sweep efficiency (E_v) is calculated by combining the areal and vertical sweep efficiencies
- Displacement Efficiency E_d

IEA-GHG suggested the following parameters to be used for estimation in case initial assumptions must be made for the volumetric estimation of CO_2 storage in the saline aquifer (Table 4).

Table 4: Average guiding parameters for storage estimation

		Low/high value by lithology		
Parameters	Symbols	Clastic	Dolomite	Limestone
Net to total area	$E_{An/At}$	0.2/0.800	0.2/0.800	0.2/0.800
Net to gross thickness	$E_{hn/hg}$	0.21/0.76	0.17/0.68	0.13/0.62
Effective to total porosity	$E_{\phi e/\phi t}$	0.64/0.77	0.53/0.71	0.64/0.75
Volumetric sweep efficiency	E_v	0.16/0.39	0.26/0.43	0.33/0.57
Microscopic displacement efficiency	E_d	0.35/0.76	0.57/0.64	0.27/0.42

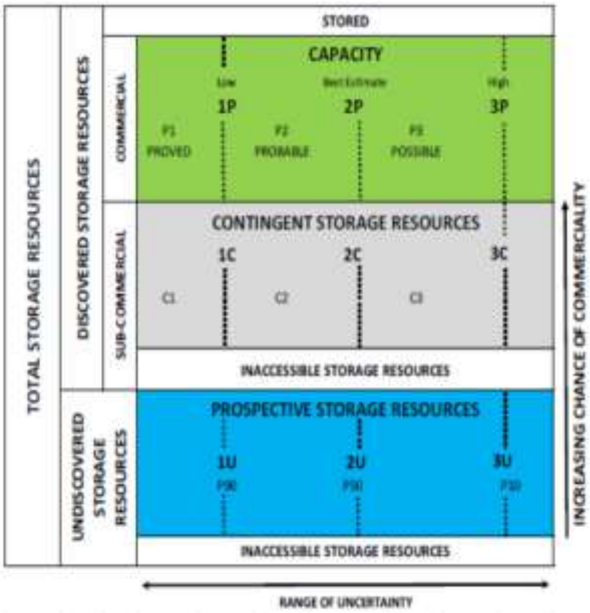


Fig. 8: Storage Classification and categorization

Reservoir simulation-based estimates of storable quantities honor the boundary conditions of a project and the proposed project development characteristics (e.g., well numbers, injection rates, water extraction, and disposal in case of the saline aquifer and pressure constraints). This method is more representative as is coupled with geomechanics and geochemical aspects also. A comprehensive 3D reservoir model, a digital representation of a target reservoir is built utilizing available geological understanding and Geophysical (G&G), rock and fluid, geomechanics and geochemical data and provide 1P, 2P and 3P capacity estimates. (Fig. 8).

Injectivity Estimation

Injectivity describes the rate of injection that can take place in each well. This will define the number of injectors required for the storage project: Formation thickness, porosity, permeability, Injection rate, wellhead injector pressure, and sweep efficiency:

- Injectivity tests on core and well
- Formation pressure
- Hydrocarbon and water saturation in pore spaces
- Temperature
- Salinity

Reservoir pressure is not very high and must have good porosity and permeability for injection, less heterogeneous, and adequate water production in saline aquifers for void age creation. Not very high salinity, Injection at the lower part of the formation, Horizontal well for higher injectivity, Saline aquifer with replenishment not preferred.

Stimulation of injectors to remove wellbore skin due to salt precipitation. Sc-brine relative permeability and capillary pressure with hysteresis. Laboratory studies suggest that 100-120 MMscf CO_2 can be injected through one well.

Types of Storage Sites

CO_2 can be stored in various geological settings as discussed below.

Depleted Oil Fields

CO_2 is injected into declining oil fields to increase oil recovery. This is an Enhanced Oil Recovery (EOR) method. Immiscible and miscible CO_2 has been applied in several fields with successful results. This option is attractive because the revenue offsets the storage costs due to additional oil recovery. Injected CO_2 in depleted oilfields swells the oil, reduces the viscosity and interfacial tension, and reduces the residual oil saturation when miscible. It works well when CO_2 sources and fields are nearby, but the additional investment is required for facility modification. Depleted oil fields are better understood in terms of reservoir characterization and provide immense opportunity for CCS. The mechanism is well understood. Oil fields with significant remaining and residual oil saturations are good candidates. Miscibility of CO_2 provides better recovery compared to immiscible mode. (Rob Arts et al 2008). One of the challenges is the handling of facilities that should address CO_2. Flow assurance and leakage in old wells, conformance would be challenges.

Uneconomical Oil and Gas Field

Depleted oil and gas fields that have become uneconomical for other hydrocarbons are suitable candidates for CO_2 storage. Such fields are well understood in terms of reservoir characterization, overburden rocks, and geomechanical properties. They are safe as they have stored oil and gas for a long time. Storage capacity in depleted reservoirs depends on the degree of depletion pressure and voidage and aquifer encroachment. Also, understand a better way to avoid leakage through cap rock by the abandoned wells. Potential for leaks exists behind well casings. Depleted oil and gas fields are better understood as a lot of static and dynamic data available. Studies have been carried out to use CO_2 for Enhanced Gas Recovery (EGR) but are limited to laboratory and modeling studies. The density and viscosity of supercritical CO_2 may provide additional gas recovery. This is yet to be tested in the field. However, its application as cushion gas in natural gas storage projects is a viable option. CO_2 storage in depleted oil fields is another area. Breakthrough of CO_2 can create a problem and potentially contaminate the hydrocarbon gas (Fig. 5).

Saline Aquifer

The global CO_2 storage capacity of saline aquifers is much greater than other alternative reservoirs, but the suitability of a potential site must be investigated carefully. Saline formations contain highly mineralized brines and have so far been considered of no benefit to humans. Saline aquifers have been used for the storage of chemical waste. The main advantage of saline aquifers is their large potential storage volume and their common occurrence. Oil and gas reservoirs are not uniformly distributed geographically, and anthropogenic CO_2 is generated in many locations that are not close to potential storage sites in oil or gas reservoirs. Therefore, a storage site that finds preference is a deep saline aquifer and is widely distributed. Saline aquifers that have sandstone as reservoir rock at a depth greater than 800 m below the ground surface or seabed are ideal reservoirs for injection and storage of CO_2, provided a good cap rock exists to act as the seal. Highly mineralized brine present in a typical saline aquifer has been found to enhance the process of mineral trapping of CO_2 through rock-brine-CO_2 interaction. The challenge though is that CO_2 thus stored, should not escape or leak from the reservoir under any circumstance. Injected CO_2 in such a reservoir may be stored as structural/stratigraphic trapping, diffusion/solubility trapping, residual trapping, and mineral trapping/mineralization. The major disadvantage of saline aquifers is that relatively little is known about them, compared to oil fields. Leakage of CO_2 back into the atmosphere may be a problem in saline aquifer storage. The injected CO_2 will dissolve in the brine and the resulting brine/CO_2 mixture will be slightly denser than the brine alone. Slow vertical flow of the denser brine will cause further dissolution, as fresh brine is brought in contact with the CO_2 phase. Trapping of a separate CO_2 phase by brine also can act to immobilize CO_2 as a residual phase. Estimates of the time scales for dissolution and the resulting vertical convection suggest that hundreds to thousands of years will be required to dissolve all the CO_2, but by that time, much of the CO_2 will exist in a trapped residual phase. Relatively slow chemical reactions, depending on the chemical composition of the brine and the minerals present in the aquifer, may then sequester some of the CO_2 as minerals. Continuous injection of CO_2 will increase pressure which may facilitate the activation of faults and may compromise the cap rock integrity. Therefore, pressure management is a critical component that is achieved by drilling water producers. This added cost to the project. The Sleipner project has demonstrated that large-scale CO_2 injection in a saline aquifer is feasible. Baklid *et al.* (1996) Because it is a high permeability aquifer with relatively high porosity at the source of the CO_2, it is an especially favorable application of aquifer injection. Gorgon project in Australia has drilled water producers for creating the pressure sink and disposal wells for managing the produced water. Several water producers have to be determined based on numerical simulation. The subsurface CCS stages and a typical storage site incorporating a storage reservoir and overburden are depicted in Fig. 8a-b. Good storage potential aquifers for CO_2 sequestration should have the following three requirements (Ringrose and Bentley, 2016):

a. Sealed geological trap: Geological trap should be a continuous subsurface structure with a 4-way closure and sealing cap rock. For the cap rock to be considered sealing, it must have enough thickness to resist the CO_2 plume pressure. Furthermore, such subsurface structures need to be accessible from the surface; therefore, avoid candidates located under the populated areas or the aquifers connected to hydrocarbon resources
b. Adequate storage capacity: Storage capacity is the total pore volume that can be occupied by CO_2 at reservoir conditions. Both the porosity and thickness of the formation would directly impact the pore volume available for sequestration. Injecting CO_2 as supercritical fluid would maximize pore volume utilization. Therefore, storage capacity depends on formation pressure and temperature to reach supercritical CO_2 (most suitable formations would have enough pressure and temperature to achieve supercritical CO_2)
c. Good injectivity: Injectivity means how easily CO_2 can flow within the storage formation. Near wellbore permeability and formation, thickness plays a major role in injectivity. In saline aquifers, formation pressure would increase which eventually reduces injectivity. Therefore, If CO_2 solubility in water is high (depending on salinity), then the rate at which formation pressure builds up will be less. Considering the above requirements, the following table summarizes the major screening criteria for optimum CO_2 sequestration candidates in saline aquifer

Un-Mineable Coal Seams

CO_2 storage in deep un-mineable coal beds is a successful method of storing the contaminant gas and improving methane production. The mechanism of improving methane is that the adsorption of CO_2 is higher than methane. Thus, CO_2 helps to desorb more methane gas and occupy its place through adsorption in a coal seam. CO_2 is a small molecule and has a better adsorption capacity than methane gas. Therefore, coal seams can adsorb more CO_2 and replace CH_4 for production. However, sweep efficiency would be a challenging part as injected CO_2 would move in cleats only. A two-step process occurs in methane production from coal seam: First diffusion from matrix to cleats and second Darcy flow in the cleats. The diffusion of CO_2 to the matrix needs to be studied. Any storage mechanism can work well if sweep efficiency is good and unfortunately, that is not the case in a coal seam (Fig. 5).

Shale Oil

CO_2 can be injected into the shale oil reservoir for enhancing oil recovery. Miscibility is achieved and recovery improvement of around 10-15% has been observed. The pilot test has given good results (Fig. 9).

Deep Sea

The ocean is one of the most oversized sinks for carbon dioxide storage. CO_2 can dissolve and disperse if injected below one km into the sea. However, concerns over the environmental impact on marine life from the acidity of seawater near the injection point cannot be ruled out. Two main concepts exist for this type of storage. They are dissolution type below 1 km and lake type at depths greater than 3000 m, where CO_2 is denser than water and is expected to form a 'lake' that would delay the dissolution of CO_2 into the environment. Theoretically, this can work as the density of CO_2 is more. However, it has not been tested so far. Any significant disturbances like tsunamis would create a major disaster (Fig. 7).

CO_2 Hydrate

Geological formations located at low-temperature, high-pressure conditions, such as aquifers located below permafrost and deep/sub-seabed, could be a viable site for CO_2 storage as hydrates since they offer limited storage, the existence of high pore pressure, very low CO_2 leakage rates in the existence of hydrate seal and long-term storage potential. Solid CO_2 hydrates have greater mechanical strength than solid ice due to the cementing effect. They have negative buoyancy due to their higher density than saline water, pore water, CO_2 gas, and ice. Concept-wise, it's a good option that has potential. The challenge is that hydrate formation may take some time and before hydrate is formed, CO_2 can migrate upward and contaminate seawater.

Other Rock Formations

There are options for geological CO_2 storage like basalt, and subsurface caverns. Minerals like serpentinite occurring in some of these formations react with CO_2 and form carbonate minerals for permanent storage.

Algae Cultivation

Algae can absorb carbon dioxide. Carbon, together with the remnants of algae can be placed on the seafloor in the deep ocean where it can stay for longer periods viz several centuries. CO_2 can be captured by microalgae and recycled into biomass, which in turn could be utilized as a carbon source to produce lipids to produce bioenergy and other value-added products.

CO_2 Storage Mechanisms

When CO_2 is injected into subsurface formations like depleted oil and gas fields and saline aquifers, it stays there in a number of ways. The following four trapping mechanisms are prominent. Stored CO_2 is distributed among them in various percentages with structural trapping topping the list and mineralization at a slow and lower percentage. Distribution of CO_2 trapping changes in these four types over periods (Fig. 10) (Widyanita and BW Zairudin, 2020).

Structural Trapping

Anticline and four-way closure of storage sites are considered one of the best sites for CO_2 storage. In this type of enclosures impermeable rock materials encase geological units and prevent the escape of CO_2. CO_2 is lighter than water and it starts rising upward in the formation after injection. It rises till caprock which is composed of silt and clays or salt and is impermeable to prevent this. This way CO_2 is accumulated beneath the caprock in supercritical form. It spreads horizontally below caprock where it is prevented by stratigraphic unconformities and pitchouts of the intervals. The sealing layer/s (e.g., mudstone, claystone, shale, evaporites) acts as a seal because the pore throats are too small to permit the gas (non-wetting phase) to enter the water-filled pores. Capillary entry pressure is high. Accumulated CO_2 starts moving downward by dispersion. Dispersion is a slow process. More than 60% of stored CO_2 remains in structural trapping which was much larger in the beginning.

Residual Trapping

Residual trapping is a phenomenon in which CO_2 is trapped in the pore space. This happens due to hysteresis when the saturation of the (non-wetting) gas phase decreases and the saturation of the (wetting) water phase increases. CO_2 is trapped in small pore spaces and is not allowed to move upward. The overall effect of residual gas trapping is that a migrating volume of CO_2 will leave behind a considerable volume of CO_2 trapped as a residual phase, thereby limiting the extent of travel of the CO_2 plume and acting as an essential storage mechanism. Residual trapping a good for the stability of CO_2 in subsurface geological formations.

Dissolution Trapping

CO_2 is a reactive compound. It forms carbonic acid when reacts with water. Various geochemical reactions can take place with fluids and mineral present. Dissolution of CO_2 in the water of saline aquifers or encroached water in depleted oil and gas fields leads to the permanent storage of CO_2 in the subsurface. These principally comprise:

- CO_2 dissolution in aquifer brine (also referred to as solubility trapping)

- CO_2 precipitation as mineral phases (referred to as mineral trapping)
- CO_2 sorption in clay minerals (with significant rates observed during some experiments)

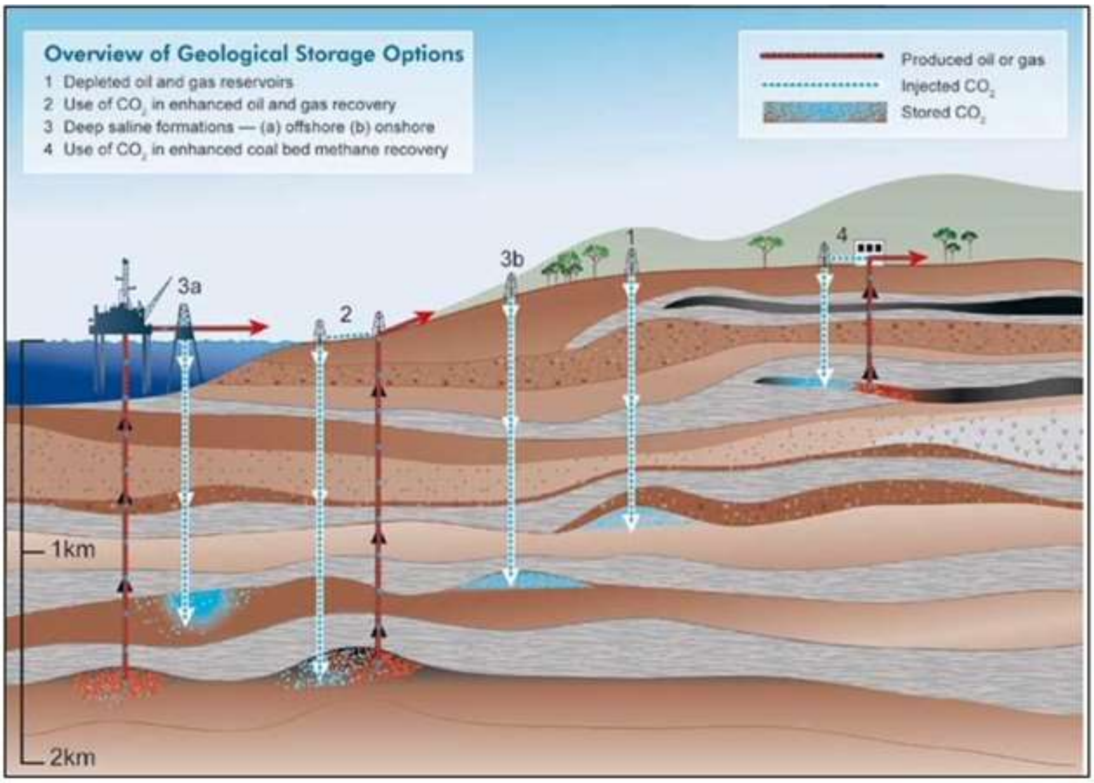


Fig. 9: Typical CO_2 Storage illustration (IPCC, 2007)

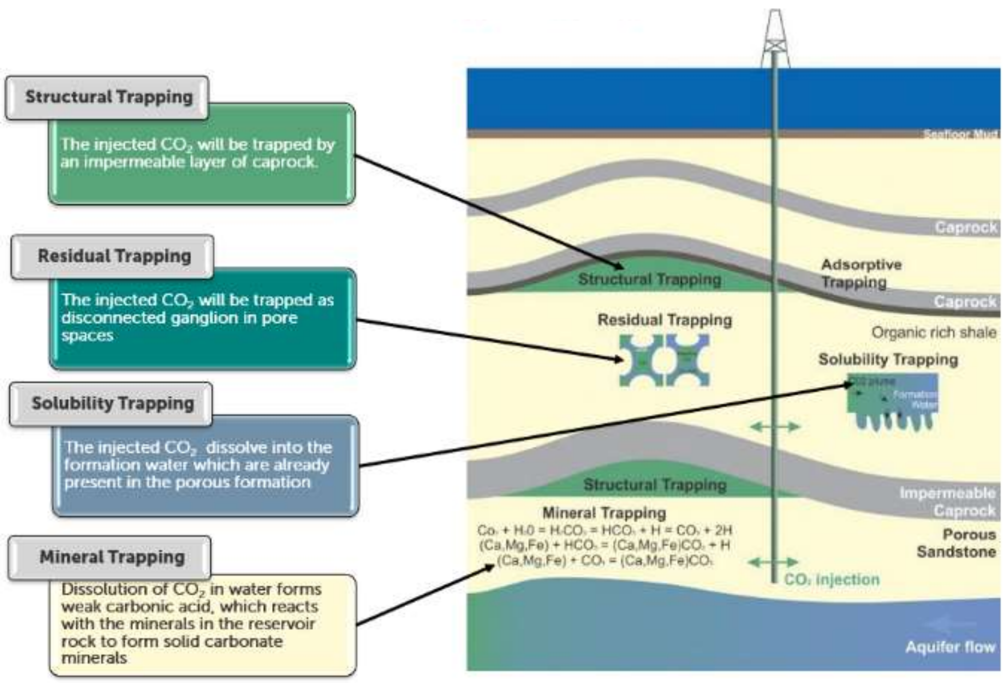


Fig. 10: Mechanisms of CO_2 storage (Widyanita and BW Zairudin, 2020)

Water with dissolved CO_2 becomes heavier and tends to move down to the bottom of the reservoir. The dissolution rate depends upon the contact of CO_2 and brine and is limited by maximum concentration. There is a continuous renewal of contacts due to the upward movement of CO_2 and the downward movement of water with dissolved CO_2. However, this process is slow. This percentage is roughly 15% in Sleipner after ten years.

Mineralization Trapping

CO_2 in the presence of brine can react with the minerals in the rock. Certain minerals can dissolve, whereas others can precipitate. This is a prolonged process and a tiny fraction of CO_2 will result in mineralization after more than 10000 years.

Geochemical reactions are studied in the lab on core samples for evaluation of property changes especially porosity and permeability, dissolution, and precipitation of minerals. These chemical kinetics data are used in numerical simulation to predict CO_2 behavior over a period of time. MMV also helps to understand the CO_2 states and changes in the reservoir.

CO_2 Capture or Separation (Forbes et al., 2009, Chemical Industry Vision 2020)

There are four major technologies in practice for CO_2 removal or separation from contaminated gas sources. CO_2 sources may be after the combustion of fossil fuels. The mechanism on which CO_2 capturing or separation works is based on the following principles:

1. Absorption
2. Adsorption
3. Membranes
4. Cryogenic process

Absorption Based

In this process, chemicals are used for the absorption of CO_2 molecules from gas streams. Absorption-based separation works in two ways first chemical absorption and second physical absorption. One of the CO_2 properties is that it has relatively higher absorption characteristics compared to other gases. This distinguishing characteristic is made use of to capture the CO_2. One of the commonly used absorbents is alkanolamines. Another method of separation in this category is physical absorption where CO_2 molecules interact with the surface of absorbents. Common physical absorbents are methanol (rectisol process) and glycol ethers (selexol process). Many times, physical solvents and reactive absorbents are used in tandem. Monoethanolamine (MEA), Diethanolamine (DEA), Diisopropanolamine (DIPA), methyl diethanolamine (MDEA), and Diglycolamine (DGA) are commonly used absorbents. Ammonia, alkaline salt solutions, and water are also used for CO_2 separation. Water works as an absorbent for CO_2 removal at high pressure due to increased solubility. One of the challenging aspects of this technology is that it is capital and energy intensive. However, absorbents used are recycled for reuse. This is a widely used technology for CO_2 separation.

Adsorption Based

Adsorption is a process in which molecules of a specific gas or liquid physically adhere to the surface of a solid. The adhering surface can be porous or nonporous solid materials. This concept is used in the separation of CO_2 from a mixture of gases. Like the absorption method of separation, CO_2 is absorbed, and, in this technique, CO_2 has adherence affinity to adsorbents.

Some of the widely used adsorbents are aluminosilicate zeolite molecular sieves, titanosilicate molecular sieves, and activated carbons. CO_2 adsorption capacities of adsorbents are not similar or constant but rather vary and depend on the characteristics of the materials. Activated carbons are used for sulfur removal from CO_2 streams. Silica gel is used for light hydrocarbon removal. Moistures from permeate streams are removed by using activated alumina, bauxite, and silica gels. There are two common methods for desorption Pressure Swing Adsorption (PSA) and Temperature Swing Adsorption (TSA). Depressurization and heating are used in PSA and TSA methods of desorption. Hybrid PSA/TSA is also used for the adsorption and desorption process. Important adsorbents are zeolites, Metal-Organic Frameworks (MOFs). One of the challenges faced in the process is the decreasing capacity of adsorption in the presence of water vapors. If the adsorption process works efficiently in the presence of water vapors, then the requirement of pre-treatment for dehydration would be reduced energy requirement and result in saving and simplification of the process. Recent developments in adsorption-based separation technologies are amin-grafted mesoporous silica and amin-impregnated solid sorbents.

Membrane Based

Membrane separation technology is a known method, which is based on the principles of physical separation based on the molecular sizes of the gases. This becomes promising in terms of cost saving and simple operation. Energy saving and footprint savings are other components that make it attractive. Membrane separation finds its applicability in CO_2/CH_4 separation in contaminated natural gas processing, CO_2 separation from flue gases in post-combustion (CO_2/N_2) and the third one is CO_2/H_2 in pre-combustion in gasification. The polymeric membrane is one of the widely used membrane technology. Separation in polymeric membranes decreases under high CO_2 partial pressure due to CO_2-induced plasticization.

Polyethylene glycol (PEG) is another membrane, but the biggest limitation is low CO_2 permeability due to crystallization. Inorganic membranes, zeolite membranes, and carbon membranes are other CO_2 separation membranes. Ionic liquid membranes are also being studied for CO_2 capture.

Membrane Contactors (MBC) Separation

MBC is a hybrid technology combination of membrane contactor technology using large quantities of hollow fiber membrane with amines solvent. The membrane will act as a physical barrier between gas and solvent. The mass transfer principle is based on the diffusion of CO_2 and H2S to the solvent-membrane boundary, where CO_2 and H2S will be selectively absorbed due to the solvent's selectivity. The solvent will absorb the CO_2 and H_2S which later will be regenerated to be reused in the closed-loop system. MBC is suitable for bulk removal of up to 25 moles % of CO_2 in the feed gas and fine removal to less than 50 ppm in treated gas. It is modular which makes it suitable for a stranded gas field, either land base, offshore or shale gas.

Cryogenic Separation

The principle in the cryogenic separation process is based on the condensation of gases which varies from gas to gas and takes place at different temperatures. Thus, a particular gas can be captured at specific temperatures. The biggest advantage is recovering pure liquid CO_2. Liquefaction of CO_2 is achieved by refrigerating the gas mixture and by the Joule-Thompson effect that results from the compression and adiabatic expansion of the stream. This is energy intensive process and this is one of the major disadvantages associated with the cryogenic separation of CO_2. This technology is good for bulk capturing CO_2 but becomes unfavorable or challenging for dilute gas streams. Additionally, the requirement is to remove gases, such as water and heavy hydrocarbons, that tend to freeze and block the heat exchangers. Cryogenic separation units can be in configurations both horizontal and vertical. Vertical ones may have better efficiency. In addition to energy requirement, the footprint for this separation technology is also bigger (Fig. 11).

Thus, liquefaction technology for CO_2 recovery is still developing. Cryogenic CO_2 recovery is typically limited to streams that contain high concentrations of CO_2, with a lower limit of about 50 vol %, but with a preferred concentration of >90 vol%. It is not considered to be a viable CO_2 capture technology for streams that contain low concentrations of CO_2, which includes most of the industrial sources of CO_2 emissions. Cryogenic separation of CO_2 is most applicable to high-pressure gas streams, like those available in precombustion and oxyfuel combustion processes.

Hybrid Separation

Two carbon capture technologies are anchored as the key technology in this study: Cryogen for bulk CO_2 removal and normal gas membrane for CO_2 polishing. So far, the dominant commercial CO_2 capture process has been solvent-based using mono-ethanolamine MEA) as the solvent. A total of 1, 127 BScf of permeate stream volume is estimated to be produced from the source field for 32 years with hybrid separation technology Polymeric membrane and Cryogen. The composition of the permeate stream is expected to consist of 98 moles % of CO_2 with the remaining 2 moles % of hydrocarbons. The estimated permeate stream rate and cumulative permeate volume peak up to 155 MMscfd in the year 2026 and the rate is anticipated to decline starting from the year 2035 onwards.

Reservoir Characteristics of CO_2 Storage Field

There is growing interest in CO_2 storage as a means to control greenhouse gas emissions brings a new challenge for reservoir modeling. There are two main purposes of reservoir models for this scenario-first capacity assessment and secondly, more detailed models to understand injection strategies and to assess long-term storage integrity. Some of the issues like compartmentalization, connectivity, permeability zonation, and flow barriers are common in oil and gas field development models (Fig. 12). However, certain issues are different, such as understanding formation response after injection of the bulk of CO_2 volume and pressure is increased and geochemical reactions with rock as CO_2 is compressed in liquid or supercritical form makes understanding of phase behavior an important factor. CO_2 storage requires a large volume of depleted reservoir or aquifer volumes and the caprock system presents significant challenges for grid resolution and level of detail (Ringrose and Bentley, 2016).

The M1 field is identified as a CO_2 storage site. This field is high-relief carbonate build-up and forms part of the Mega Platform complex comprising Saderi and Jintan with a common regional aquifer. It is divided into four reservoir zones, namely Top of Carbonate (ToC), zone 2, zone 3, and Zone 4. The gas is found in TOC, zone 2, and Zone 3. The porosity ranges from 4-46%. Average porosity and gas saturation within the gas leg from well logs is 35 and 91% respectively.

The average core permeability is 519 mD in the gas zone whereas well test permeability varies from 600-1560 mD. The initial reservoir pressure and temperature are 3440 psi and 246° F at datum 4800 ft TVDSS respectively. The field has strong aquifer support. This pressure and temperature are important from a storage point of view as CO_2 will be in supercritical condition. The Gas Oil Contact (GOC) is at 4945 ft and the water-oil contact is at 4970 ft. The reference pressure and depth for the initialization are set at 3454 psia and 4945 ft. Newmann and Hall's equation was used to estimate the C_f of 1.2E-06 and 3.0 E-6 psi^{-1}.

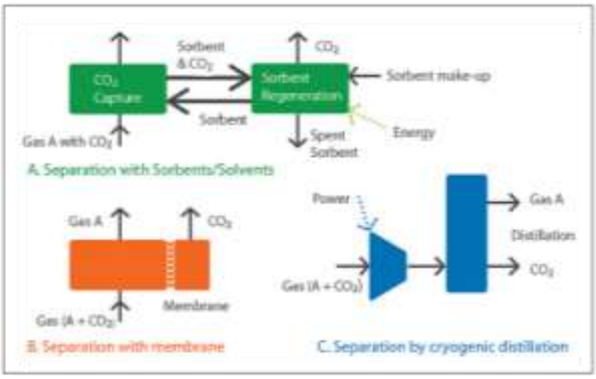


Fig. 11: Schematic of various separation methods

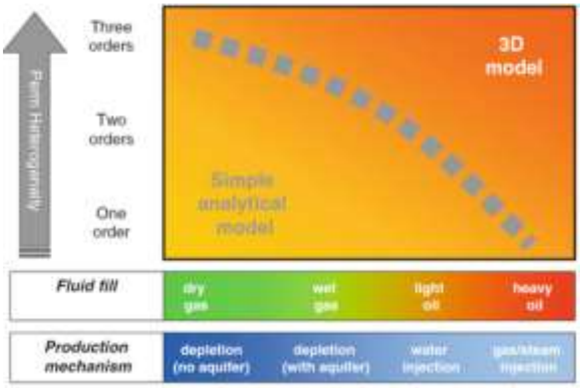


Fig. 12: Reservoir model choice based on heterogeneity and fluid type (after Ringrose and Bentley, 2016)

However, there is evidence that M1 has an overpressured zone in which M1 should have a higher C_f than a normal reservoir. The final C_f used in the model is 3.0 E-5 psi^{-1}. The estimated GIIP was 2897 Bcf and 61.42 MMstb of condensate. Contaminants are 2.9% CO_2 and H_2S less than 100 ppm. The reservoir has an oil rim with a huge gas cap. Relative permeabilities considered for modeling fluid flow in the reservoir are imbibition water oil and drainage gas oil systems. The same set of relative permeabilities was used for history for matching and knowing the reservoir dynamics, fluid distribution, and aquifer encroachment at the time of the start of CO_2 injection. The model was initialized by using gravity initialization for a saturated reservoir with a gas cap with saturation averaged over the depth interval covered by a grid block. In this approach, if a grid block has its block center slightly above the gas-oil contact, the gas saturation assigned to the block is the average over the block volume of the local gas saturation and not simply the gas saturation value in the gas cap. The field has been producing since 1996 with a recovery factor of 76%. The field has a strong water drive causing a pressure depletion of about 700 psi. (Masoudi *et al*., 2012; 2013; Widyanita and BW Zairudin, 2020).

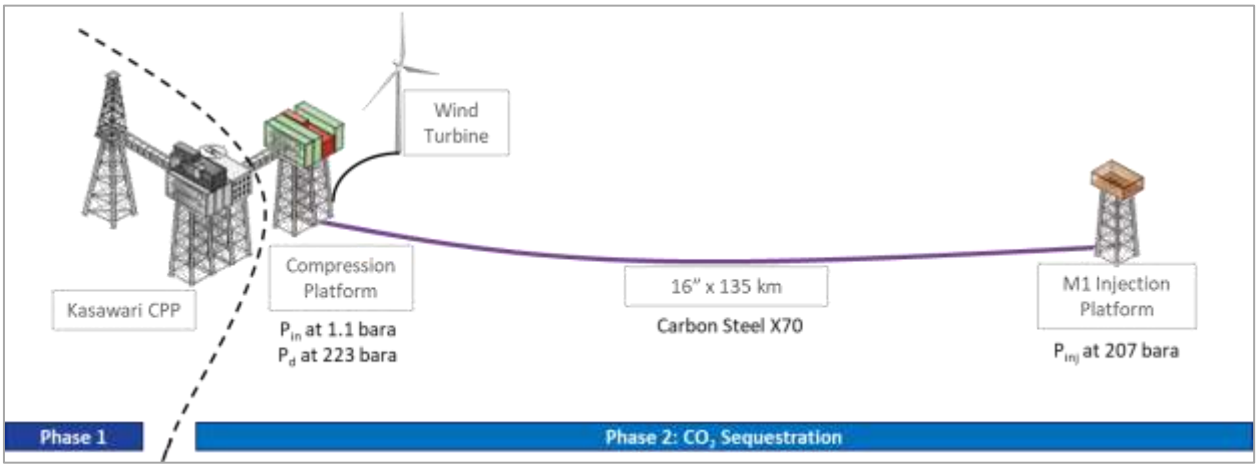
The SDP of a depleted gas field in offshore Sarawak, Malaysia comprises capture units at the source platform and separated CO_2 permeate would be transported through a 135 km long CO_2-resistant metallic pipeline to the sink platform which has injectors (Fig. 13a). The planned CO_2 permeate for injection would be 155 MMscfd (Fig. 13b).

Laboratory Studies

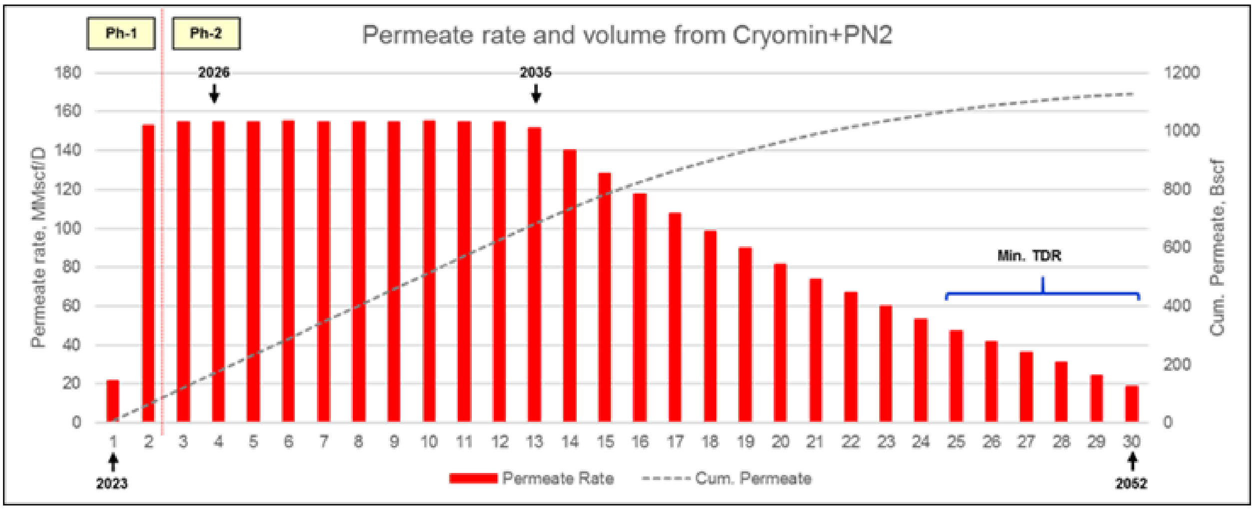
Extensive laboratory studies need to be carried out for understanding the geochemical and geomechanical effects under varying saturation and pressure conditions of CO_2 injection (Fig. 14). These data are required in numerical simulation to estimate storage volume, pressure increase, and movement of CO_2 plume in the reservoir and overburden. CO_2 injectivity tests on core plugs are required to be carried out to have an idea about injection rate, potential formation damage, salt precipitation, and firming up the number of the injectors (Fig. 15). Injectivity tests suggest that more than 120 MMScfd can be injected.

The CO_2 injected in the reservoir may potentially overcome the capillary entry pressure of the overlying caprock. The CO_2 may diffuse from the reservoir into the caprock, dissolve in the water and react with the caprock minerals.

The calculation considers a diffusion of porewater coming from the reservoir and saturated with CO_2 at 3553 psi and 134°C. The pH becomes slightly more acidic at the base of the cap rock, but the buffering effect of the carbonaceous minerals stabilizes the pH at values not very far from neutrality. The rock buffers strongly the diffusion of the reactive gas. Dolomite and Siderite have precipitated at the base of the caprock and the clay mineral, Chlorite has dissolved in the first 4.5 m of the caprock. The dissolution of illite has been replaced by the precipitation of Kaolinite. Gypsum has also dissolved in the first 1.75 m. The resistance of the caprock to the diffusion of CO_2 from the reservoir is high, with only approximately 1.7 m affected by the total disappearance of the major clay, Illite, after 10,000 years of interaction. The S2 field has an immediate seal of approximately 460 m thick. Only ~2 m of the seal will be affected by the CO_2 diffusion. This suggests that the caprock is resistant and a low risk of CO_2 leakage through diffusion is expected for S2. The RCA and XRD analysis was done for the pre-aging core and post-aging core, to get mineral dissolution/precipitation which impacts porosity changes due to rock geochemical reaction. The kinetic batch aging study suggests the dissolution of 2 and 1.6% p.u. in two samples. CO_2 injection into carbonates (or rocks with carbonate cement), some dissolution of carbonate minerals will occur but when formation water becomes saturated with CO_2, the injected CO_2 will remain in a separate phase (Tewari *et al*., 2021).



(a)



(b)

Fig. 13: (a) CO_2 transport pipeline; (b) Schematic of separated CO_2 transportation from the source platform to sink platform and CO_2 permeate for storage in a depleted gas field

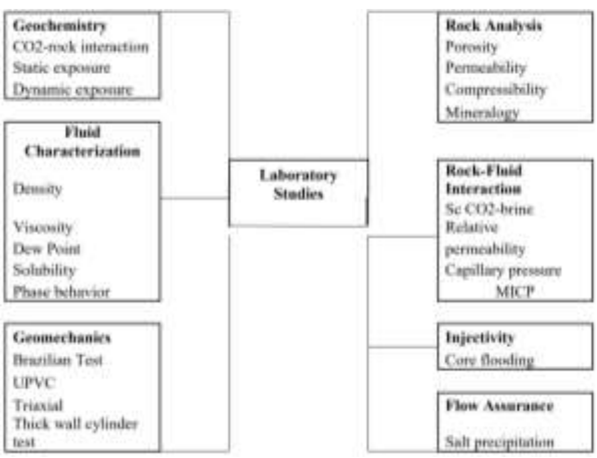


Fig. 14: Laboratory studies for CCS

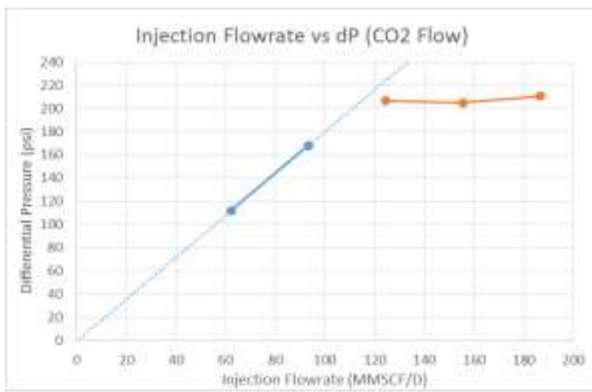


Fig. 15: Laboratory experiments for CCS study input (Tewari and Sedaralit, 2021)

Geomechanical Processes and Modelling

CO_2 injection and storage operation will increase fluid pressure, temperature change due to cooling by the injected CO_2, and chemical interaction between CO_2-rich brine and the rocks. In the case of injecting into a depleted reservoir, the reservoir will undergo pressure depletion and associated compaction and porosity reduction before the injection, which will be transmitted to the surface in the form of subsidence. These changes and interactions will impact the stress condition in the reservoir and the overburden (Bissell *et al*., 2011). Assessment is required on the impact of the complex inter-related changes in the stresses, pressure, and temperature, associated deformation on cap rock, fault seal integrity, compaction, and associated subsidence to manage CO_2 containment and mitigate risks related to leakage. The coupled in-situ stress, pressure, and thermal behavior while injecting will impact the initiation and propagation of the hydraulic fracture, containment of the fracture within the injection zones, and integrity of the caprock and fault seal. Hence, a comprehensive coupled geomechanical study needs to be conducted as part of the feasibility evaluation of injecting and storing CO_2 in a field.

Coupled Geomechanics Dynamic Modelling Methodology

Coupled geomechanics dynamics modeling is required to be conducted for both the production stage and CO_2 injection period in the case of injecting into a depleted reservoir. The associated modeling workflow (Fig. 16) starts with constructing the 3-D geomechanical model based on the dynamic reservoir model grid. It uses 1-D geomechanical models as one of the critical inputs (Tan *et al*., 2022). The dynamic reservoir model grid is required for the coupled modeling between the geomechanical and reservoir models.

In the geomechanics-dynamic coupled modeling, at selected stress steps, the reservoir simulator will pass data including pressure, CO_2 concentration within the plume, water saturation, and temperature to the geomechanical simulator. Changes in stresses, rock mechanical, and petrophysical properties based on laboratory CO_2-rock interaction test data, displacements, strains, and deformations will be computed by the geomechanical simulator using the data from the reservoir simulator. The coupled geomechanics-dynamics modeling evaluates CO_2 leakage risk associated with rock properties degradation due to injected CO_2 interaction with the caprock and reservoir rock, fault reactivation, breach of caprock integrity, CO_2 cooling on caprock and reservoir rock, hydraulic fracture initiation and propagation through the caprock as well as compaction and associated subsidence.

Modeling Results and Discussion-Geomechanics Impact on Dynamic Reservoir Modelling and CO_2 Storage

Two-way coupled geomechanics-dynamics modeling was conducted for both the production stage and the CO_2 injection period. Further investigation, including the impact of geomechanics towards dynamic reservoir simulation and CO_2 storage, is conducted to:

- ✓ Evaluate changes in rock mechanical and petrophysical properties based on laboratory CO_2 rock interaction test data
- ✓ Analyze the potential of fault reactivation throughout the production and injection phase for overburden and reservoir faults
- ✓ Investigate caprock integrity throughout the production and injection phase
- ✓ The evaluation of changes in rock mechanical and petrophysical properties due to CO_2 interaction was based on the CO_2 plume concentration data from the dynamic simulator together with data obtained from laboratory tests. The following tests and analyses were conducted on pre-and post-CO_2 treated “sister” reservoir rock and overburden shale samples from an adjacent field to determine the changes in the rock properties due to the interaction
- ✓ Single and multi-stage triaxial tests
- ✓ Brazil tensile strength test
- ✓ Uniaxial pore volume compressibility test
- ✓ Petrophysical, petrography, and mineralogy analyses

The comprehensive CO_2 interaction laboratory study found the interaction resulted in a reduction in rock strength properties by between 4 and 12%, whilst Young's modulus decreased by up to 8% and Poisson's ratio increased by up to 10%. The increase in Poisson's ratio corresponds to the reduction in rock stiffness. Similar changes in Young's modulus and strength properties due to CO_2 interaction were also applied to the fault stiffness and strength properties.

The coupled geomechanical modeling assessed fault reactivation throughout the production stage and injection program, which may pose the risk of CO_2 leakage from the storage regions. The faults were modeled using the "equivalent material" concept for rock mass which "smears" out the influence of each discontinuity set throughout the fault elements they occupy. The comparable properties of the overburden and reservoir faults used in the study are shown in Table 5. Fault reactivation was analyzed based on induced fault plastic shear strain which may provide a flow path for CO_2 leakage. The fault plastic shear strains at the end of production and injection were deficient, indicating a low risk of fault reactivation, in Fig. 17. Only localized plastic strain was observed in the shallow overburden faults and the reservoir faults with the plastic shear strain of up to 0.01 and 0.03%, respectively.

The cap rock integrity was also evaluated by analyzing any induced plastic shear strain to determine the caprock's state (Fig. 18). The results showed that the caprock did not undergo shear failure and maintained its integrity at the end of the production period (The year 2020) and injection program (The year 2048) caprock at top of the reservoir at end of production and injection program.

The fundamental CO_2 cooling impact on caprock and reservoir rock includes:

- Hydraulic fracture initiation at injector due to cooling and propagation under reduced fracture gradient in the reservoir and through the caprock
- Fault reactivation due to stress changes in reservoir and caprock associated with cooling.
- Shear failure in caprock due to stress changes and stress transfer between reservoir and caprock

One-way coupled geomechanics-dynamics thermal modeling was conducted, which showed that temperature change was localized within about 2,000 ft in the vicinity of the CO_2 injectors. At the start of the CO_2 injection, the CO_2 plume initially moved toward the top of the reservoir as it displaced the encroached water. However, as the injection continued, the CO_2 plume was pushed downward more profoundly into the reservoir due to the buoyancy effect of the higher-density supercritical CO_2. This is illustrated in Fig. 19, which shows the movement of the cooler region (light and dark purple) deeper into the reservoir as the CO_2 injection progressed. The implication is that larger temperature and horizontal stress decreases are observed in the upper perforation zone during the early years of injection. Still, they occur in the lower perforation zone during the later injection years.

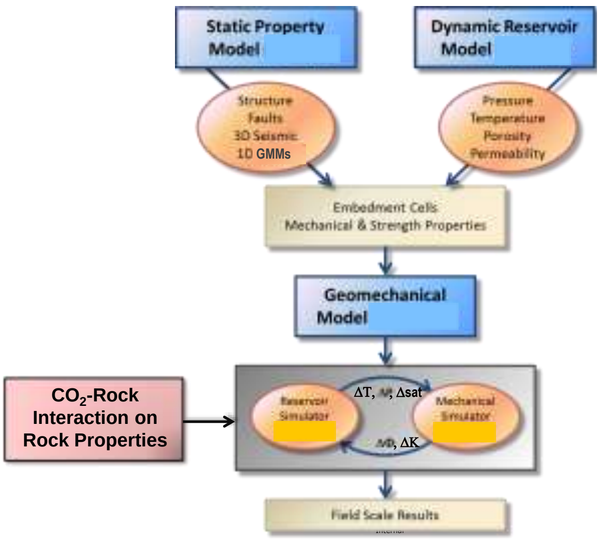


Fig. 16: Coupled geomechanical modelling workflow for CO2 injection and storage

The evaluation was made on the potential of hydraulic fracture initiation at the injector and propagation of the hydraulic fracture through the reservoir and caprock due to the reduction of fracture gradient by CO_2 cooling. The results from the evaluation are summarized in Table 6. It was found that hydraulic fracture will be initiated at CO_2 Inj A but not in CO_2 Inj B. However, the initiated hydraulic fracture is unlikely to propagate through the reservoir as the injection pressure is well below the minimum fracture gradient pressure in the reservoir. Furthermore, the minimum fracture gradient pressure in the caprock is higher than the minimum fracture gradient pressure in the reservoir and the caprock provides an additional fracture propagation barrier.

However, the evaluation needs to be conducted for the entire injection period as the fracture initiation and propagation pressures in the reservoir and caprock as well as the injection pressure will change as the injection progresses. With subsequent further cooling, hydraulic fracture initiation could occur at a later stage of the injection period. It is worth noting that hydraulic fracture propagation in the reservoir will not breach the containment integrity as long as the hydraulic fracture does not propagate through the caprock.

Compaction Impact on CO_2 Storage Capacity

The carbonate reservoir has high porosity and the uniaxial pore volume compressibility test data of reservoir rock from an adjacent field showed pore collapse behavior which generated the large deformation. As the reservoir depletes during production, the rock deformation will result in compaction and pore volume decrease, impacting the total storage capacity for the CO_2 injection. Compaction is partially transmitted to the surface in the form of subsidence. With subsequent CO_2 injection, only the elastic compaction and pore volume decrease can be recovered with the pressure increase from the injection. Likewise, the subsidence can partially rebound with CO_2 injection.

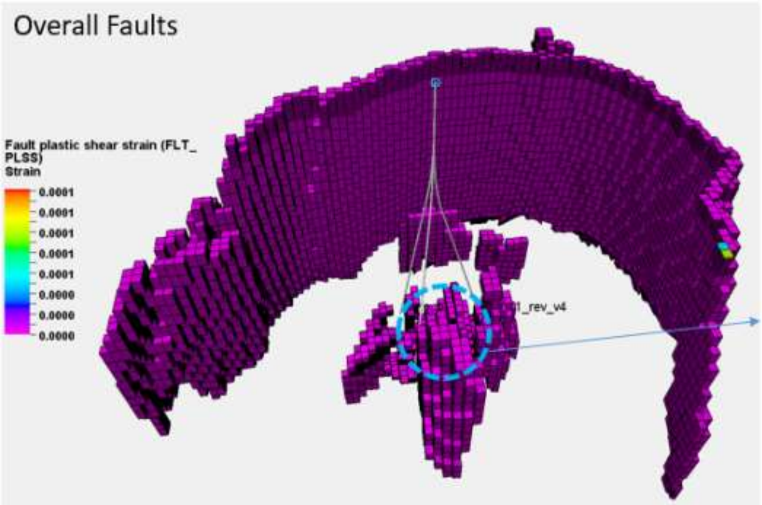
The comparison of the predicted seabed subsidence at the platform location with the Global Positioning System (GPS) monitoring data is shown in Fig. 20. It shows a good consistency between the predicted and measured subsidence till present-day and it provides confidence in the reservoir compaction prediction, which impacts the CO_2 storage capacity prediction. The forward prediction of the seabed subsidence during the CO_2 injection program showed a slight seabed uplift of 1.1 ft. The small seabed uplift was due to the reservoir undergoing pore collapse. The compaction is primarily plastic deformation during production, which is unrecoverable with increased reservoir pressure during CO_2 injection.

Table 5: Overburden and reservoir fault properties

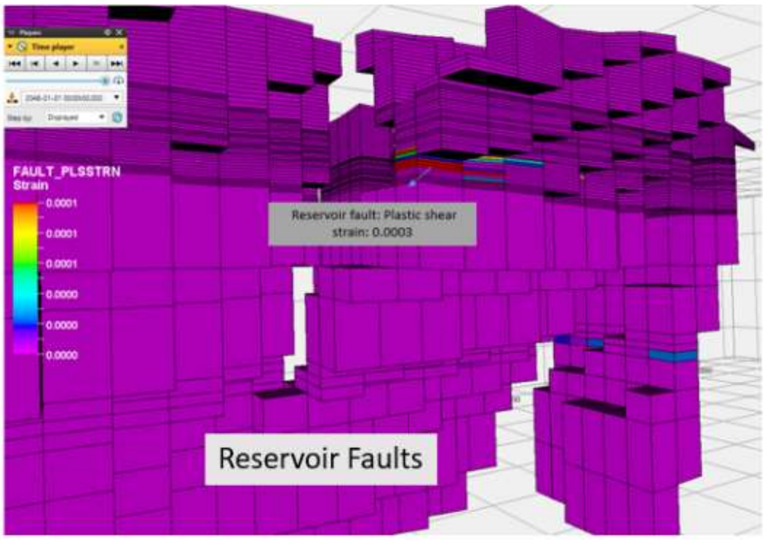
Fault property	Overburden fault	Reservoir fault
Normal stiffness (psi/ft)	713-1092	2010-4800
Shear stiffness (psi/ft)	324-496	913-2181
Cohesion (kPa)	1	1
Friction angle (degree)	21.4-25.7	32.9-33.8
Dilation angle (degree)	10.7-12.8	16.4-16.9
Tensile strength (kPa)	1	1

Table 6: Summary of fracture initiation pressure at CO_2 injectors and minimum fracture gradient pressure in reservoir and caprock due to CO_2 cooling at end of injection program

Well	Injection pressure (Psi)	Fracture initiation pressure (Psi)	Maximum fracture gradient pressure in reservoir (psi)	Maximum fracture gradient pressure in cap rock (psi)
CO_2 Inj A	2980	2828	3110	3948
CO_2 Inj B	2979	3224	3000	3841



(a)



(b)

Fig. 17 a-b: Fault plastic shear strain distribution in the overburden and reservoir faults at the end of the injection program

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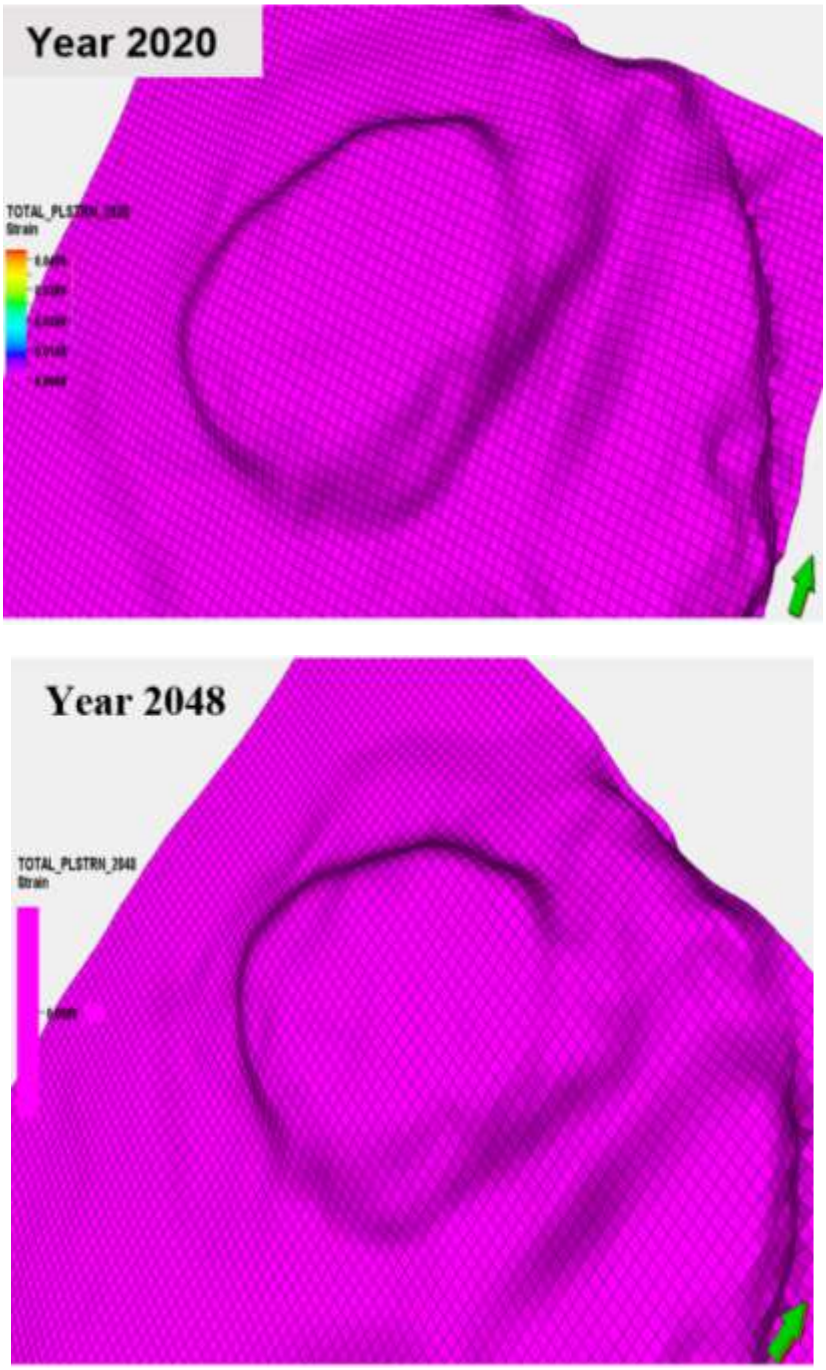


Fig. 18: Plastic shear strain distribution in caprock at the top of the reservoir at the end of production (the year 2020) and injection period (the year 2048)

The estimation of the pore volume change is based on the resultant volumetric strain, which is calculated in the coupled geomechanical modeling. The changes will impact the total storage capacity for the CO_2 injection and properties in the reservoir, such as porosity and permeability. Table 7 shows the mean change values of pore volume and permeability in the hydrocarbon, aquifer, and total reservoir interval. The permeability was updated based on the Carman-Kozeny equation. There is no considerable reduction in pore volume after the year 2010 and the most significant drop is at the end of production in the year 2020. As CO_2 is being injected, there is a slight increase in the pore volume of 0.1% while the increase in permeability is also minimal at 0.2% at the end of injection in the year 2048. The minimal increase in pore volume is due to the irrecoverable plastic deformation associated with pore collapse in the total reservoir interval.

The coupled geomechanical modeling results on potential fault reactivation, cap rock integrity breach, caprock weak point limit, seabed subsidence and uplift, and CO_2 cooling effect on cap rock and reservoir rock were subsequently used to quantify the CO_2 injection pressure and injectivity scenarios at the design limit and initial reservoir pressure limit and their respective storage capacity. In addition, the trapping mechanisms, i.e., supercritical CO_2 (structural trapping), residual CO_2, and dissolved CO_2, were also quantified.

Geochemical Interaction Processes and Modelling

The injection of supercritical CO_2 in a geological reservoir will modify the physicochemical equilibrium in the host rock. Dissolution of CO_2 in the formation water causes acidification and this phenomenon accelerates the dissolution precipitation reactions which may modify the mechanical and hydraulic properties of the rock. The characteristics of the fluid containing CO_2 change as it moves away from the injector well and with time. Hence, the geochemical reaction needs to be studied in order to reduce the subsurface storage risk by capturing geochemical and geomechanical effects on fluid flow and CO_2 storage. Complex coupled geochemical-dynamic geomechanics coupled modeling is required because the three processes are interrelated. (Chidambaram *et al*., 2021). For example, CO_2 mineral reactions will lead to dissolution or precipitation in carbonates directly affecting geomechanical properties that cannot be fully evaluated experimentally. Furthermore, the injected CO_2 will react with reservoir rock leading to either dissolution of reservoir rock and/or precipitation of solids that are products of the geochemical reactions causing a net change in porosity and permeability. Hence, it is critical to use the 3-way coupled modeling approach that integrates the dynamic model, geochemistry model, and geomechanics model to obtain the cumulative effect of all three processes. This provides a more accurate estimate of CO_2 storage capacity along with a reduction in storage risk,

In the coupled modeling workflow in Fig. 21, the dynamic model is at the center which passes input parameters to the geochemical and geomechanical models. Once the dynamic model receives the updated porosity and permeability values back from the geochemical and geomechanical models, the dynamic model incorporates them before proceeding to the next simulation stress step.

Modeling Results and Discussion

Laboratory studies have been carried out to develop an understanding of the geochemical and geomechanical effects under varying CO_2 injection saturation and pressure condition. These data are used in numerical simulation for estimating the storage volume, pressure increase, and potential movement of CO_2 plume in the reservoir and overburden. The CO_2 injected in the reservoir may potentially overcome the capillary entry pressure of the overlying cap rock and diffuse from the reservoir into the cap rock, dissolve in the water, and react with the cap rock minerals. The dissolved CO_2 will react with carbonates such as calcite and dolomite. However, these reactions may provide sufficient buffering capacity (via bicarbonate alkalinity) to resist drastic changes in pH. The presence of reactive carbonates such as calcite in a host reservoir will have a major impact on how the chemical reactions evolve during CO_2 injection.

Temporal changes in porosity due to mineral dissolution and precipitation can affect fluid flow. The dissolution of minerals such as calcite changes the formation porosity. These changes in porosity and corresponding changes in permeability caused the changes in fluid flow patterns. When this occurs, there is additional pore space to accommodate the brine and CO_2. The changes in porosity were calculated from changes in volume fractions of minerals caused by the mineral reactions at each stress step conducted in the simulation. The permeability may be updated using the Carman-Kozeny equation or look-up tables if the resultant porosity change is significant.

In a study (Tewari and Sedaralit, 2021), the calculation considers diffusion of pore water coming from the reservoir and saturated with CO_2 at 3553 psi and 134°C. The pH becomes slightly more acidic at the base of the cap rock, but the buffering effect of the carbonaceous minerals stabilizes the pH at values not very far from neutrality. The rock buffers strongly the diffusion of the reactive gas. Dolomite and siderite precipitated at the base of the cap rock and the clay mineral, Chlorite dissolved in the first 4.5 m of the cap rock. The dissolution of illite was replaced by the precipitation of kaolinite. Gypsum was also dissolved in the first 1.75 m. The resistance of the cap rock to the diffusion of CO_2 from the reservoir is high, with only approximately 1.7 m affected by the total disappearance of the major clay, illite, after 10,000 years of interaction. The field has an immediate seal of approximately 460 m thick. Only approximately 2 m of the seal will be affected by CO_2 diffusion. This suggests that the caprock is resistant and there is an expected low risk of CO_2 leakage through diffusion for the field.

Table 7: Mean pore volume and permeability changes during production and injection program

	Reduction of pore volume (%)			Reduction of permeability (%)		
Interval	2006	2020	2048	2006	2020	2048
Hydrocarbon	4.8	5.2	5.2	11.7	15.1	15.0
Aquifer	2.9	3.2	3.1	0.5	2.4	2.2
average pore volume	3.0	3.3	3.2	11.0	14.4	14.2

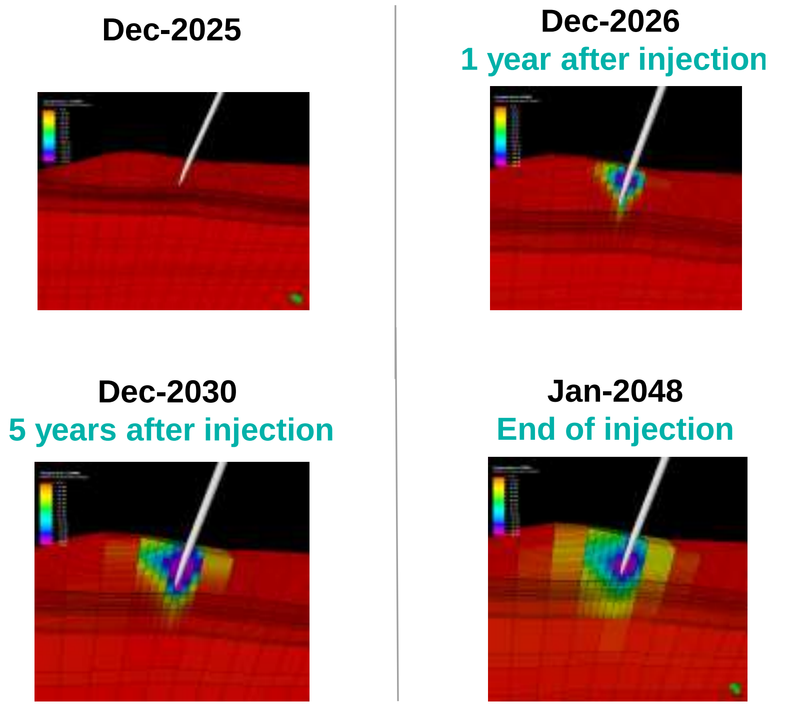


Fig. 19: Progressive movement of the cooler region (light and dark purple) at 1 year and 5 years after injection and end of injection

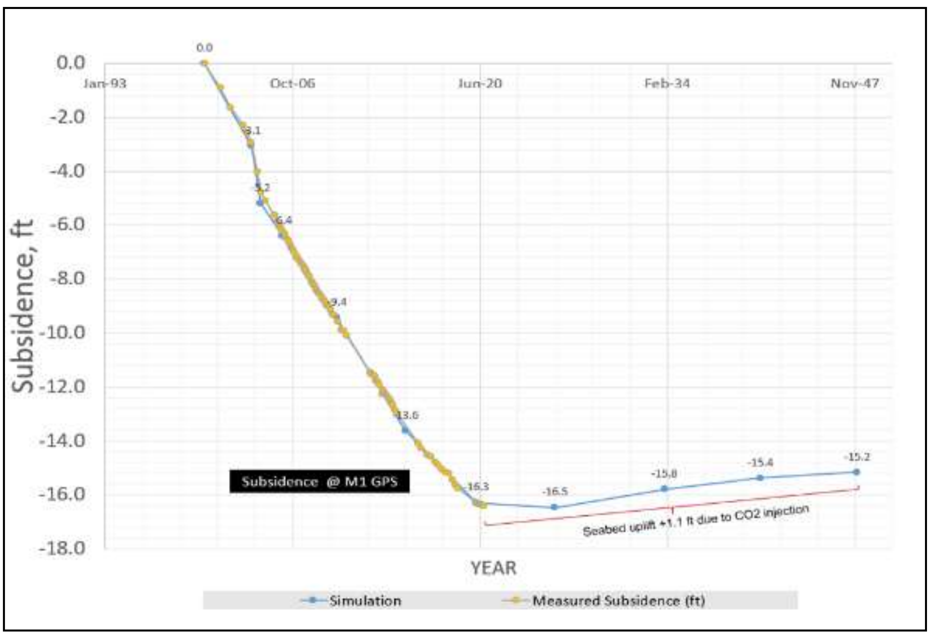


Fig. 20: Comparison of the predicted seabed subsidence at the platform location (orange circles) with the GPS monitoring data (blue circles) till present-day and predicted seabed subsidence till the end of the CO_2 injection program (Tewari *et al*., 2022)

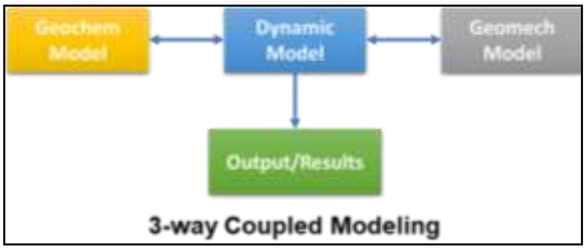


Fig. 21: Schematic representation of 3-way coupled dynamic-geochemistry-geomechanics modelling (Prasanna *et al.,* 2021)

Routine Core Analysis (RCA) and X-Ray Diffraction (XRD) analyses were conducted for pre- and post-treated samples in order to determine the mineral dissolution/precipitation which will impact porosity changes due to the rock-geochemical reaction. The kinetic batch aging study suggests the dissolution of 2 and 1.6% p.u. in two samples. CO_2 injection into carbonates (or rocks with carbonate cement) will encounter some dissolution of the carbonate minerals. However, when the formation water becomes saturated with CO_2, the injected CO_2 will remain in a separate phase. Poorly buffered systems (e.g., sandy sediments/aquifers) are devoid of sufficient quantities of alkalinity-producing minerals and therefore, lack the ability to resist changes in pH. A major concern for systems with high CO_2 solubility and/or low pH buffering ability is that any geochemical change due to CO_2 intrusion is likely to be more apparent and the risk for pH-induced perturbation to environmental quality is more significant and prolonged compared to well-buffered systems.

Measurement, Monitoring, and Verification (MMV)

CO_2 stored in geological formations must stay forever. With proper site characterization and implementation of the MMV plan, the risk of unexpected leakage can be minimized and managed. The permanence of stored CO_2 in the subsurface must be confirmed at a high level of accuracy. It is also expected that the potential for leakage to decrease over time as other mechanisms like the dissolution of CO_2 in water, residual trapping, and mineralization provide additional hindrances for escaping CO_2. MMV tools enable operators to measure influenced parameters s of the site at surface and subsurface conditions during and after CO_2 injection and to use these measurements to analyze, simulate and forecast CO_2 behavior with time and also plan mitigation in case of any unexpected eventualities. This makes MMV activities a critical component of safe geologic storage and they should occur throughout the life cycle of a storage project. (Das *et al*., 2022; Tiwari *et al*., 2021a-b. The important parameters for MMV (Fig. 22 and Table 8):

- Monitoring for injectant or displaced fluids is used to update and validate the subsurface models to bring more reliability
- Monitoring of reservoir pressure change and in-situ stress diagnosis if any breach in the confining zone (*s*) taking place
- Monitoring of pressure and temperature in overburden caprock and above the confining zone allows early detection of CO_2 movement outside the confining zone (*s*)
- Monitoring of good integrity ensures safe injection that fluid is leaking behind the casing
- Monitoring CO_2 concentrations and fluxes and fluid composition at the surface and in the groundwater, table ensures safe CO_2 injection
- Seabed monitoring is also conducted for potential leakage of CO_2. This leakage may happen through wells or faults. pH may get change. CO_2 migration into an overlying porous formation may also happen due to integrity in the wells which may impact the formation's pore pressure, temperature, and fluid chemistry. Seismic methods may be able to detect pressure changes in the monitoring zone and may provide an alternative to direct measurements of the deep subsurface
- Maintenance of good integrity is essential because a good failure could create a conduit for flow between all formations penetrated by the well and the surface

The risk associated with the leakage of retained CO_2 is through seabed which could cause serious environmental perturbations, particularly acidification, in marine ecosystems. Therefore, the study should be carried out for quantifying the effects of acidification derived from CO_2 leakage on marine organisms. Leakage at the seabed would change the pH of seawater. pH would be more severe near the location of the CO_2 leakage, decreasing the pH values in the surrounding area. The new pH conditions and the expansion of the plume of acidified seawater caused by such an event will depend on many factors such as the duration and rate of the leakage, tidal cycle, wind strength, regional circulation, and currents. (Table 9 and Fig. 23).

Risk Assessment in Offshore CCS

Any viable CO_2 storage site may include a number of hazards (Table 9). They need to be identified and quantified for proper mitigation. Hazard identification should focus on the main potential pathways of the leakage: (1) Insufficiency of the confining units or caprock failure, (2) Penetration through wells, (3) Transmission through faults and fracture, and (4) naturally occurring or induced seismic events (Forbes *et al*., 2009).

Risk and Uncertainty in CCS

CO_2 capture and storage are highly technical in nature. There are a number of uncertainties at every stage. It becomes important to identify all possible uncertainties and rank them which can be easily understood by subject matter experts and in some cases by laymen. Risk management will enable the maturation of CO_2 capture and storage projects. Quantification of uncertainty does not have much value in itself if it does not influence the decision-making and operation and management processes. A mitigation plan has to be made to de-risk the projects for parameters if not all the major ones. Uncertainty may exist in geological sites, formation deposition, porosity and permeability, reservoir continuity and heterogeneity, caprock/seal continuity and integrity, presence of faults and sub-seismic faults, fault sealing and compartmentalization, presence of fractures in formation and overburden, basement characteristics, geochemical and geochemical parameters, Phase behavior of CO_2 including impurities, Sc CO_2 brine relative permeability and hysteresis, CO2 injectivity, flow assurance issues like salt precipitation and hydrate formation, capturing, transportation. CO2 leakage may take place through legacy wells which must have been remediated even though could be a potential source for leakage.

CO_2 injectors, observation wells, and water producers if the storage site is in a saline aquifer could be conduits for leakage. These uncertainties may affect storage volume, containment, and injectivity of CO_2 and may also impact the number of injectors and their locations and over/under the design of facilities.

Proper understanding and adequate data will help in the formulation of a good project and implementation strategy. Measurement, monitoring, and verification will help to analyse the local over-pressurization, hydrodynamic movement of CO_2, plume migration movement directions, and leakages. Mitigation plans may include well remediation, reduction in injection rates, drilling of pressure relief wells and temporary venting of CO_2, and in case of severe challenges abandoning the site and developing an alternate storage site. Existing know-how encompasses standard oil and gas techniques, such as workover completion, decreasing injection pressure, partial or complete gas withdrawal, water extraction to relieve pressure, shallow gas extraction, etc.

Safety Criteria During Operation and Post-Closure

Expertise and know-how of the companies for the safe operation of CCS projects are important. Oil and gas companies have good experience in oil and gas production, water and gas injection, steam injection, etc. However, CO_2 storage is different in many aspects. It is not reverse gas engineering. It is much different in terms of wells and their metallurgy; injection fluid and associated pressure increase and plume movement. Safety criteria in project design, during operation, and post-closure must be documented upfront for a successful project, especially for eventual leakage.

Table 8: MMV Techniques and Analysis

Parameters	Techniques	Analysis and information
Container footprint	4D surface seismic4d DAS VSP Cross well seismic reservoir saturation tool vertical profiling electrical surveys seismic microseismic microgravity InSAR /GPS monitoring wells	Monitoring the CO_2 plume movement and pressure geometry incorporating the data in numerical simulation induced fractures if any potential leakage around the well's changes in pressure and temperature around the well's mitigation plans
Well performance and integrity	Pressure Downhole Gauge (PDG) distributed temperature sensing step rate test pressure fall off test wellhead pressure and temperature VSP wellhead pressure and temperature pressure falls off tests mechanical integrity tests of wells cement and casing imaging (USIT/CBL)	Evaluating integrity of container and wells evaluating injection performance chemomechanical process salt precipitation hydrophysical process fine migration Wettability of CO_2-rock hysteresis in capillary the pressure and relative permeability conformance flow assurance hall and hall derivative plots Well intervention for mitigation stimulations
In-situ stress surface and marine CO_2 concentration monitoring	Microseismic downhole stress tools marine water and soil sampling CO_2 monitors Atmospheric surveys Sides can sonar Soil gas surveys LIDAR side scan sonar	Evaluating integrity of wells monitoring of CO_2 monitoring leakage of CO_2, early detection and planning of mitigation CO_2 content for CO_2 mass balance calculation and flowrate to conform any potential leakage along existing wells and faults

Table 9: Leakage risks

Risk scenarios	Remediation and mitigation
Leakage through caprock, faults, fractures and spill points	Lower injection rates/pressure or stop injection lower reservoir pressure of the container by removing water or other fluids create a hydraulic barrier at the top of the container by chemical sealant Produce stored CO_2 and re-inject in the more suitable competent reservoir
Leakage through active or legacy abandoned wells	Repair the wells with replugging repair injection wells with standard techniques plug and abandoned injectors which cannot be repaired using chemical sealant barriers stop injection as a last resort

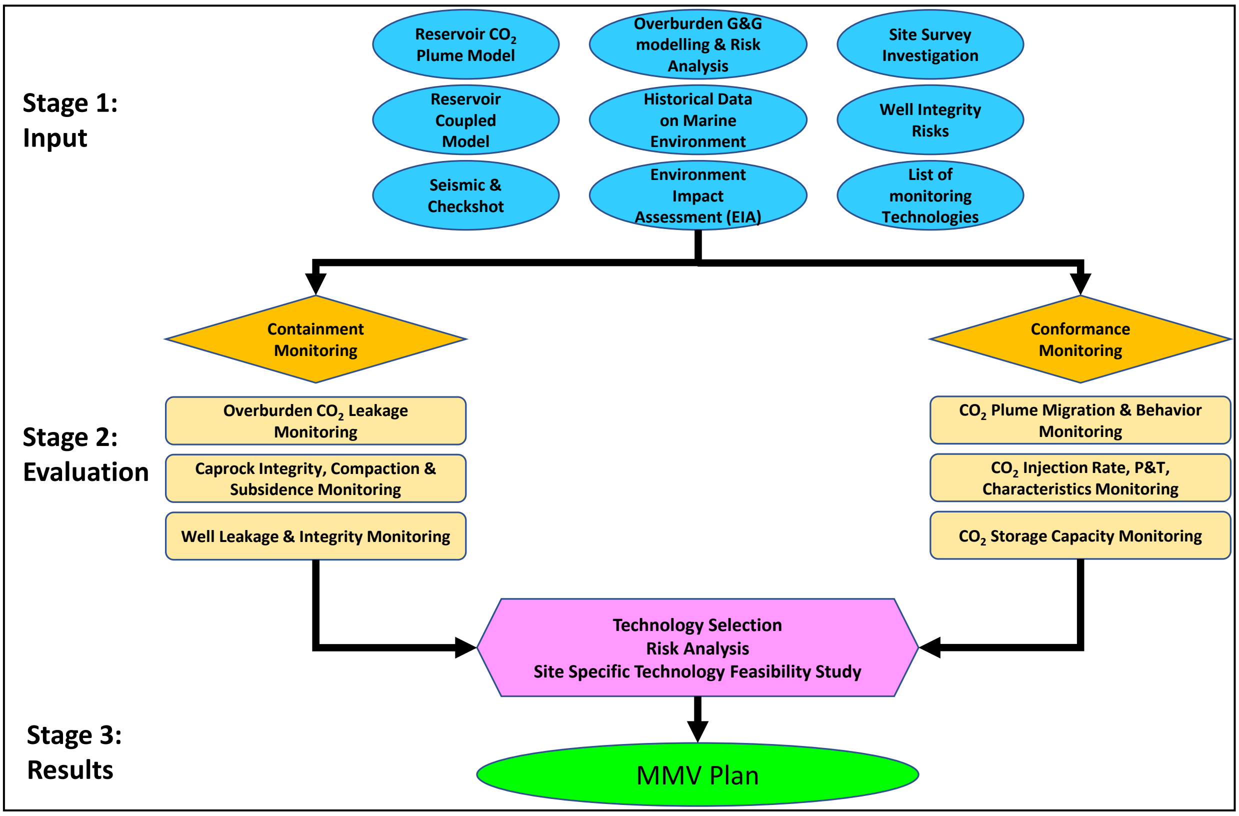


Fig. 22: MMV stages and requirements

Fig. 23: Evaluating well integrity (Patil *et al*., 2021, Smith *et al*., 2011)

The main parameters to be monitored and controlled are:

- CO_2 wellhead injection pressure and flow rate must be selected such that pressure is maintained below fracture pressure to avoid the initiation and propagation of fractures. This will limit the overall injection volume
- Maintaining the CO_2 injection rates and volume as predicted by modelling studies
- Composition and phase behavior of CO_2 stream
- the integrity of the injection, observation, and legacy wells present in the injection area
- Extension of the CO_2 plume and detection of any leakage

During injection, the actual behavior of the injected CO_2 will need to be repeatedly compared against predictions. The monitoring program should be updated and corrective actions are taken if it becomes critical based on anomalous behavior observed. In the case of suspected leakage, appropriate monitoring tools could be focused on a specific area of the storage site, from the reservoir up to the surface. This would detect the ascent of CO_2 and, moreover, any adverse impact that could be harmful to drinking-water aquifers, the environment, and, ultimately, human beings. Post closure phase starts after the injection of CO_2 ceases and wells should be properly closed and abandoned adopting standard guidelines, the modelling and the monitoring program updated and, if necessary, corrective measures are taken to reduce risks.

CO_2 Transportation Management

CO_2 transport involves handling the captured and separated CO_2-rich gas/liquid streams and transporting them to the storage site. This can be done using pipelines, ships, or tankers. Pipelines are preferred for transporting large amounts of CO_2 for distances up to around 1,000 km. CO_2 amounts smaller than a few million tonnes of CO_2 per year or for larger distances overseas, the use of ships, where applicable, could also be economically attractive. When fluid travels in the pipeline long distances, it is expected that phase change will occur due to pressure and temperature variations. CO_2 may have thermodynamic properties variations which means that it must be handled across the phase transitions during the transport of gas-phase, liquid-phase, and dense-phase (supercritical).

CO_2 corrosion is one of the most common forms of corrosion resulting in loss of wall thickness in carbon steel in oil and gas production. When CO_2 dissolves in an aqueous phase, it poses problems of corrosion by promoting an electrochemical reaction between steel and the contacting aqueous phase. CO_2 corrosion is affected by some factors including environmental, metallurgy, and hydrodynamic parameters. When the CO_2 permeate stream contains moisture, it is removed to prevent corrosion and to avoid the costs of constructing pipelines of corrosion-resistant material:

- ✓ CO_2-rich streams contain various other gas components (mainly hydrocarbons, nitrogen, and oxygen) which complicate CO_2 management
- ✓ CO_2 transport and flow assurance technologies are still relatively immature
- ✓ Non-Metallic Pipeline (NMP) is an alternative pipeline material to transport the CO_2 for control corrosion

Carbon Market

The term ‘carbon trading’ was coined in 1997 in response to the Kyoto Protocol, which directed industrialized countries to reduce their GHG emissions. In this view, carbon emission is considered a commodity, forming a carbon trading system. In the Paris Agreement, three options to reduce GHG emissions were addressed:

- ✓ Set a certain limit that an organization cannot exceed
- ✓ Introduce a carbon tax where organizations pay for the CO_2 they produce
- ✓ Implement an emission trading scheme to create a carbon market

The last option has been obtaining traction due to the positive support of clean producers of energy. In addition, the Fossil fuel industry producers are incentivized to become more efficient and gradually crab their emissions. This resulted in the establishment of carbon credits, a tradable certificate or permit that gives the right to emit one ton of carbon dioxide or an equivalent of another GHG. A carbon emission allowance is allocated by a regulator and audited by a certification authority. As the threshold is exceeded, organizations should purchase the remaining emission quota from those who were able to save carbon emission credits. There are issues in carbon trading for accounting and validation. It is in the maturing process.

Social Acceptance

Subsurface injection of CO_2 in the depleted oil field is an established technology and is in practice for the last 50-60 years with significantly improved oil recovery. However, engineered CO_2 storage in saline aquifers is not practiced in a big way. A major uncertainty in Saline aquifers is that they are not well understood which can be understood thoroughly with more data acquisition, study, and analysis. One of the biggest apprehensions in common mind is whether injected CO_2 will stay forever or will it leak to the surface or contaminate the potable water. These doubts in the mind of common people need to be addressed as the majority may have "not in my backyard syndrome". Continuous engagement with the public with the help of experts with full transparency will make them aware of science and dispel their doubts and resistance.

Standards, Best Practices, and Policies

Subsurface storage of CO_2 is not new. Standards and best practices are quite developed. However, any standard or best practice does not supersede national or international regulations, treaties, or protocols. Projects can acquire a certificate of conformance against ISO27914 or ISO27916 for a defined stage in the CCS project maturation process and verification from an independent third party with the relevant technical capabilities, to verify against a set of defined criteria, likely from a national or international standard or best practice. A million tonnes of CO_2 abatement every year would require millions to billions of initial investments for the implementation of various capacity projects. A strong policy will attract give confidence to the investor and their money and determine ROI for any climate change technology. In the absence of regulations, international agencies' regulations can be customized and adopted. These regulations must address the gamut of CCS projects starting from site selection, capturing, transportation, and injection monitoring during injection and post-closure.

Policies may address the following points:

- ✓ Economy-wide emission reduction targets
- ✓ Focused sector's emission reduction targets
- ✓ CCS deployment targets and programs

- ✓ Fiscal incentives such as capital and operational support for CCS deployment
- ✓ Promulgation of CCS-specific legal and regulatory regimes which address all aspects of the project lifecycle and the establishment of capacity within institutions to apply them
- ✓ Removal of legal barriers to CCS
- ✓ Introduction of a robust carbon trading
- ✓ Sustained research and development support
- ✓ Public Education and International Collaboration

SDP is certified by experts and agencies, and it has huge benefits. This is discussed below.

Operator certification supports dialogue with regulators, partners, investors, and the public. Speed up approval for operation.

Regulator certification helps to sanction the projects in the absence of regulations and policies and guidelines. A project with international certification provides that extra level of confidence over and above local regulations. Released funds.

Public: Certification provides confidence among the masses and government for safe storage projects and removes apprehension of leakage from their minds. Transparency in reporting.

Investor/insurer: Certification provides confidence for investment and attracts partners. Due diligence becomes easier and smooth. Pave way for more storage projects for the operator.

Transparency and reporting a key element of transparency is for project operators to provide accurate and verifiable data on how much CO_2 has been sequestered on a net basis along with documentation, preferably third-party verified, of the quantification of those stored volumes, generally through a regulatory accounting body.

Environment Impact Assessment (EIA) Study

It is essential that regulatory frameworks and oversight mechanisms are designed and capable of ensuring "environmental integrity for carbon capture and storage projects to achieve approval. The three pillars of environmental integrity in geologic sequestration are:

- ✓ No CO_2 leakage into the atmosphere
- ✓ No groundwater contamination
- ✓ No significant earthquakes

In the absence of these conditions, geologic carbon sequestration will fail to achieve its potential, either because of literal leakage of sequestered CO_2 back into the atmosphere, because project proponents will fail to gain or retain a social license to operate, or both. Leading regulatory authorities recommend assurance of the following elements to be covered in the environmental impact (EIA) study:

- ✓ Carbon dioxide stream characterization
- ✓ Site selection and characterization
- ✓ Storage unit adequacy-
- ✓ Well, construction and completion
- ✓ Well, operation
- ✓ Testing and monitoring plan
- ✓ Emergency and remedial response plan
- ✓ Post-injection site care
- ✓ Injection well plugging
- ✓ Site closure
- ✓ Safety and environmental protection
- ✓ Induced seismicity

Enabler and Project Oversight

Getting the rules right is a necessary but not sufficient precondition for CO_2 sequestration with environmental integrity. How those rules are implemented is just as and possibly even more important. This means having a trained regulatory staff for permitting, inspections, model assessment, site closure, and any other functions related to CO_2 sequestration projects for their lifetime. In US comprehensive training program for sequestration regulators covering the following topics is progressing:

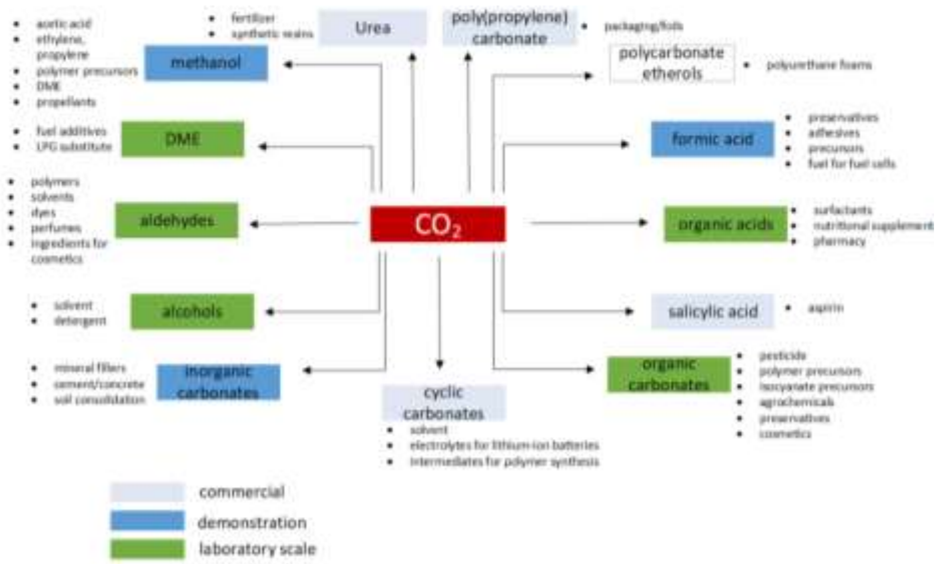
- ✓ Review of permit-relevant properties and characteristics of CO_2
- ✓ Assessing the sufficiency of storage site characterization data and model inputs
- ✓ Evaluating fluid flow modeling and assessing the proposed area of review
- ✓ Understanding and reviewing site-specific risk analyses
- ✓ Assessing, reviewing, and enhancing monitoring plans
- ✓ Evaluating monitoring and model results toward assessing long-term secure storage
- ✓ Preparing for contingencies with corrective action and remediation plans
- ✓ Closure and post-injection site care considerations
- ✓ Comparison of storage in EOR, depleted fields, and saline formations
- ✓ Understanding of financial assurance issues for geologic storage

Utilization

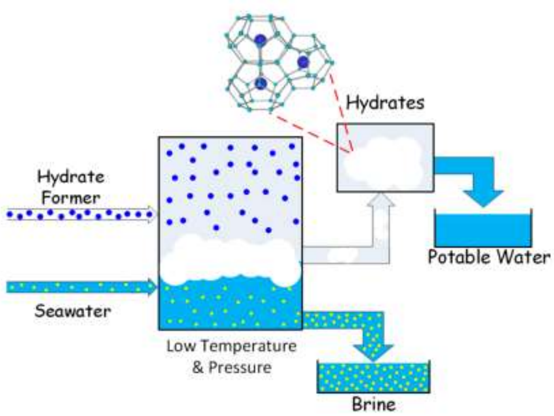
CO_2 is a stable molecule. It requires energy to break down or its reaction with other molecules to form different compounds. CO_2 has been converted to a number of products. Reactions are well-known in the application. Research is ongoing currently for new products and useful applications. The important point to be addressed in the research is to increase the yield of the product with highly efficient catalysts. The essence of CO_2 utilization is "turning waste into wealth". CO_2 utilization pathways can be classified by their physical state during the CO_2 conversion process. All three major forms of CO_2 viz. liquid, solid, and supercritical are utilized. This is depicted in Fig. 24 (a-b).

Technology Roadmap

Carbon capture, geologic storage, and carbon utilization are all well-understood technologies, especially for enhancing the oil recovery in maturing oilfields and successful large-scale integrated projects are already in operation around the globe. However, engineered CO_2 storage is not very old, and related technology and research are in the developing stage. Opportunities remain to improve performance, reduce costs, discover new uses for CO_2, and implement regulatory frameworks and international standards to provide certainty in permitting and operation of CCUS projects. A technology roadmap is one of the most important components in developing the know-how and management and planning for CO_2 storage projects. It includes research and development, establishing laboratories and geological characterization and modeling of storage sites for volume estimates, and establishing criteria for permanency in storage. The main role of a technology roadmap (Fig. 25) is to support the company's long-term technology requirements, management and planning, policy formulation, standards and norm, and identification of collaboration and focus on self-reliance (Tewari and Sedaralit, 2021).



(a)



(b)

Fig. 24: CO_2 utilization opportunities a, after (Bazzanella and Bazzanella, 2017) and b, after (Babu *et al*., 2018)

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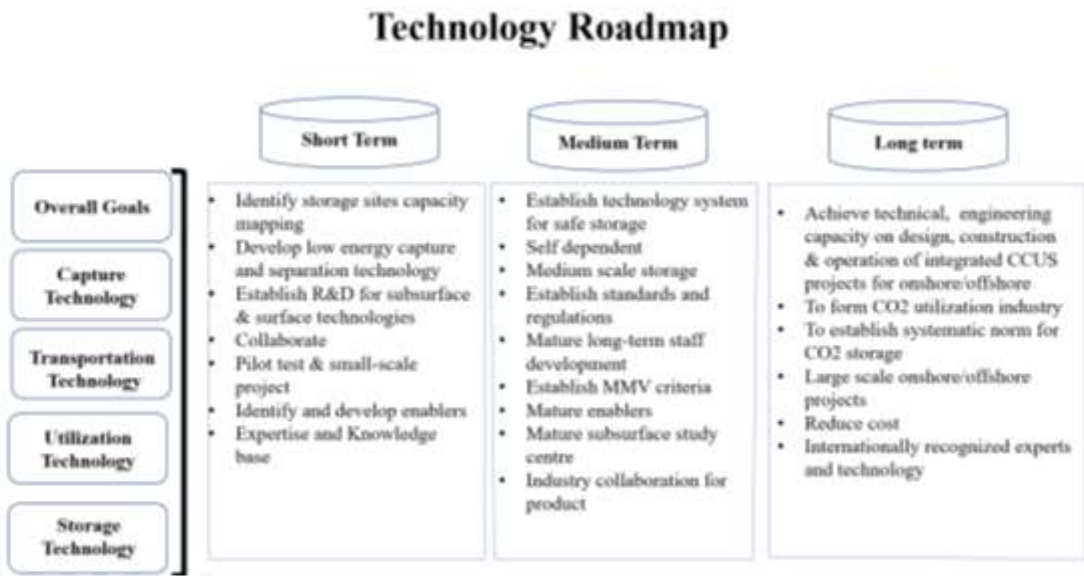

Fig. 25: Technology Roadmap

Conclusion

1. Greenhouse gas concentration is continuously increasing in the atmosphere and the oil and gas industry is also considered as one of the contributors. CO_2 concentration is around 380 ppm which is 100 ppm higher compared to the pre-industrial revolution. This will result in to increase in the atmospheric temperature
2. A serious effort is being taken up to contain the emission and manage the inevitable CO_2 emission through the capture and storage process in subsurface
3. All the steps like CO_2 capture/separation, transport, and storage are critical and must be accomplished thoroughly
4. Efficiency and yield for CO_2-utilized products require R&D for improving the efficiency and yield
5. A toolkit approach would be helpful for designing a comprehensive CCS project
6. Short-term and long-term technology roadmap would be key for mastering the technology
7. Screening of suitable storage sites is paramount as CO_2 must stay there forever for storage
8. A comprehensive coupled geomechanical study needs to be conducted as part of the feasibility evaluation of CO_2 leakage risk associated with fault re-activation, failure of caprock, and interaction of the injected CO_2 with caprock and reservoir rock due to injecting and storing CO_2 in a field
9. Efficient separation and injection along with comprehensive MMV is a must. Any compromise would derail the project and may result in a catastrophe in future
10. The output from the coupled dynamic-geomechanical modeling and coupled geochemical-dynamic-geomechanics modeling were subsequently used to develop recommendations from geomechanical and geochemistry perspectives for CO_2 injection and storage operation, including the CO_2 injection pressure and injectivity scenarios at the design limit and initial reservoir pressure limit and their respective storage capacity
11. The study formulated a comprehensive contaminated gas field development and separated CO_2 storage in an offshore environment. 900MMMSCFD raw gas production and 155 MMSCFD CO_2 injection are linked. This combined effort would be a great contribution to GHG management
12. The information and workflow may be adopted for the evaluation of other CO_2 projects in both carbonate and clastic reservoirs worldwide

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Author's Contributions

All authors listed have made equal scientific contribution to the work and approved it for publication.

Ethics

The study does not pose conflict of interest.

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