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CO_2 Storage in a Giant Depleted Carbonate Gas Reservoir -Addressing Feasibility and Design Challenges with Field Data

Siqing Xu, A. Al Keebali, M. Baslaib, A. A. BinAmro, I. Ali, A. Vantala, B. El Yosef, and M. Farouk Abdelazim, ADNOC, Abu Dhabi, UAE; S. Perumalla, C. Mascagnini, F. Benaichaoui, C. Harper, H. Singh, and S. Pandya, Baker Hughes, UAE; H. Kasekar, IO Consulting, UAE

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Abstract

An integrated study on CO2 storage in a giant depleted gas reservoir was completed. The objectives were to assess feasibility, potential capacity and timing for CO2 storage. Significant design challenges were addressed, including thermal-geo-mechanical impact on cap-rock integrity due to injection CO2 cooling, hydrate, injection well life cycle design and clusters location and surface facilities options. Further de-risking is recommended and ongoing.

An integrated approach was adopted combining/optimizing requirements from reservoir, injection wells, cap rock integrity, surface clustering, CO2 transportation and compression/pumping. Key impacts were accounted for: injection J-T effect, hydrate, stress changes, cap rock integrity, well life cycle design, existing well integrity, costs, and surface facilities. Single well models were developed for injection cooling simulation and well design options. 3D reservoir simulations were performed for reservoir pressure changes, storage options, thermal and geo-mechanics for cap rock integrity. Surface facilities options were evaluated, arrival pressure and temperature impact. Several iterations were carried out aiming at optimizing project economics with uncertainty analysis. Results from a CO2 field injection test are presented, part of key design input.

Detailed 3D reservoir simulations show that CO2 injection start-up timing and ramping up strategy are important: starting early helps additional gas recovery, late would exacerbate injection CO2 J-T cooling. Placing CO2injectors further away from producers helps enhanced gas recovery. The results of an extended actual field CO2 injection tests are presented, showing downhole temperature changes with injection rate and transient stabilization. Existing well logs and stress profile measurements were combined. Single well models were developed to simulated cooling around well-bore. Velocity strings, small tubing sizes, are potential injector design options. Hydrates formation was found in certain scenarios. Thermal-Geo-mechanics analysis show appreciable stress changes possibly propagating > 150m into cap-rock. Although CO2 surface arrival temperature can be boosted by installing heaters, but would incur higher costs and additional requirements on wellhead design. It became apparent that individual subject requirements would affect the overall design. An iterative-looping integrated approach was adopted

with CO2containment and maximizing project economics as over-riding objectives. Overall CO2 storage capacity was maximized. Adequate field data/measurements are essential and critical modelling input. Further de-risking recommendations include core laboratory geo-mechanical testing, further CO2 field higher rate testing, and comprehensive existing well integrity assessment.

Introduction

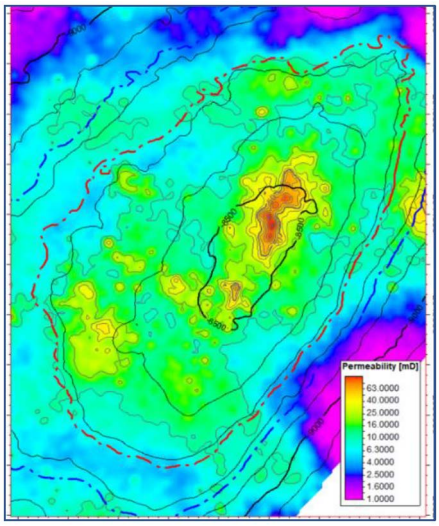
The majority of countries have signed the Paris Agreement - a landmark first reached at COP21 in 2015. Essentially, the Paris Agreement pledges to keep average global temperature rises to below 2 °C from pre-industrial levels. Since 2015 and in support of the implementation of the Paris Agreement, the past few years have witnessed an escalation in the language of climate change, a growing number of countries declared Net Zero policy commitment targets. Transforming the global economy to achieve net-zero greenhouse gas emissions by mid-century is now accepted as the objective in the global climate change discourse. However, transitioning to Net Zero is considered a tremendous challenge, not least from a technology readiness point of view. Many industries' and companies' are intending to develop plans to significantly reducing greenhouse gas emissions (GHG), and one relatively mature technology being considered is carbon dioxide capturing and permanent sequestration in underground geological formations. In the 2022 annual report by the Global CCS Institute, a significant increase in activities to develop Carbon Capture and Storage (CCS) projects were observed. Although there are still many challenges, CCS is increasingly seen as a key technology as well as opportunity in the efforts for climate control. While many of these projects plan to sequestrate CO2 in deep saline aquifer formations, there are also a large number of projects where the sequestration targets depleted hydrocarbon reservoirs – especially depleted gas reservoirs. A good number of examples can be found from the North Sea sector from the published literature.

To support the UAE climate control commitments and Abu Dhabi National Oil Company (ADNOC) strategic drive for decarbonization, an integrated multi-disciplinary feasibility study was conducted assessing the potential for CO2 sequestration in hydrocarbon gas reservoirs Onshore Abu Dhabi. The study brought together multi-discipline expertise from Geology, Reservoir Engineering, Geomechanics, Geochemistry, Production, Well Integrity, Surface Facilities, HSE and Economics. This paper presents the workflow, integration and key findings addressing the technical challenges.

Reservoir Description

The giant gas reservoir (Reservoir A) is located Onshore Abu Dhabi. The reservoir is of Lower Cretaceous deposited in an anticlinal structure, orientated Northwest – Southeast. The gas reservoir has a very thick cap rock. The reservoir has a significant thin oil rim on the west and south flanks. The reservoir has several hundreds of well penetrations, and more than 30 wells were cored. Average porosity is around 18%, average permeability ranged 5 - 10 mD.

First gas production was in 2001, and has continued since in depletion mode. The aim is to achieve >90 % gas recovery aspiration. This study is therefore looking at the potential of CO2 sequestration in Reservoir A nearing or by the end of hydrocarbon gas production and oil rim development. The figure below shows average permeability and reservoir thickness.



CO2 Storage Scenarios

CCS Dynamic Simulation Model

Evaluation was conducted by means of numerical simulation in order to assess storage requirements as well as to study and establish a range of annual CO_2 storage rates and ultimate storage volumes/capacities, plus determine the distribution of pressure across the reservoir as well as the plume migration. Likewise, the potential benefit of using the injected CO_2 as an EOR process was also evaluated.

From the ranking exercise, candidate reservoir "A" was selected for assessing the CCS process through dynamic simulation. Candidate Reservoir "A" is a carbonate reservoir that was originally filled with a gas cap that overlayed an oil rim, which overlayed an aquifer Figure 1.

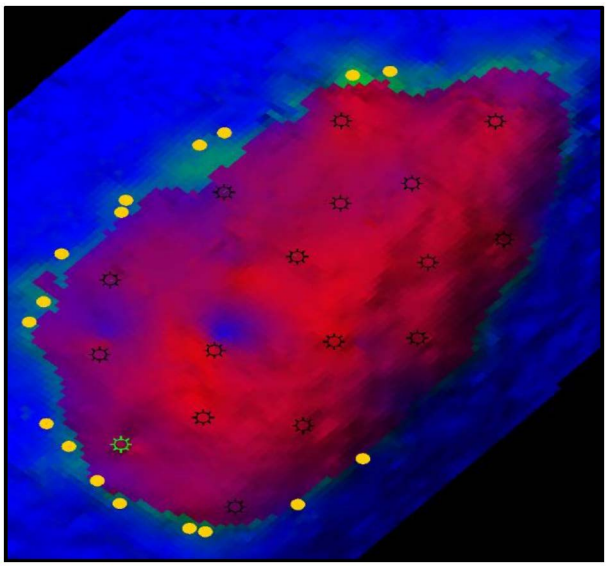


Figure 1—Candidate Reservoir "A"

CCS Dynamic Model Calibration and Conversion

The reservoir dynamic model grid dimensions were 147 × 90 × 23 (x, y, z direction) with a total of 304,290 grid cells. The total number of active cells was reduced to 289,862 with variations on their dimensions but the mean grid dimensions were 655.4 × 654.9 × 2.2 ft.

The provided dynamic simulation model had a miscible compositional fluid model. Its fluid behavior had been characterized by defining the Peng-Robinson Equation of State with eleven components where CO_2 is one of them. A non-directional end-point scaling option had been applied to the eight saturation functions that had been generated, to describe the movement of the reservoir fluids, gas, oil and water, within the reservoir.

The conventional hydrostatic equilibrium option had been used to initialize the dynamic simulation model. The initial reservoir pressure had been defined at a predefined datum, with a gas-oil contact and an oil-water contact. Likewise, the provided dynamic simulation model had been calibrated against historical data, Figure 2.

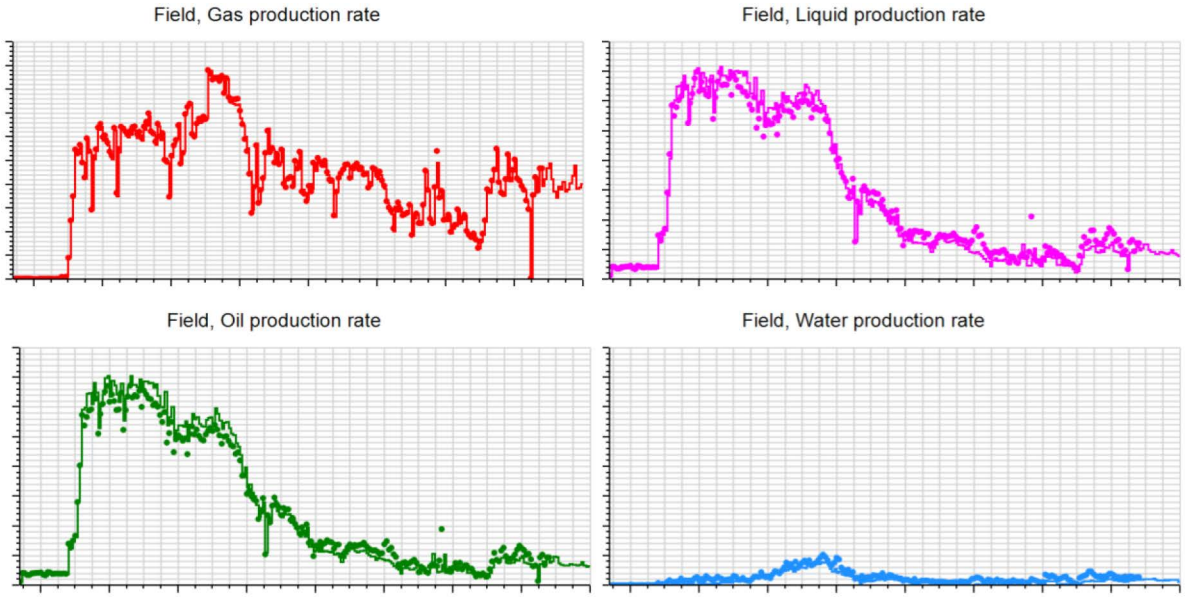


Figure 2—Dynamic Simulation Model Calibration

The dynamic simulation model was converted from the provided simulator code to a specific simulator option in order to capture all the CO_2 trapping mechanisms the usually get involved during a CCUS process. The converted dynamic model was run until the end of the history match with the aim of assessing the potential impact that the model conversion could have on the history match process and results. Figure 3 shows that there was an insignificant impact on the history match after converting the model since the results from both cases overlap.

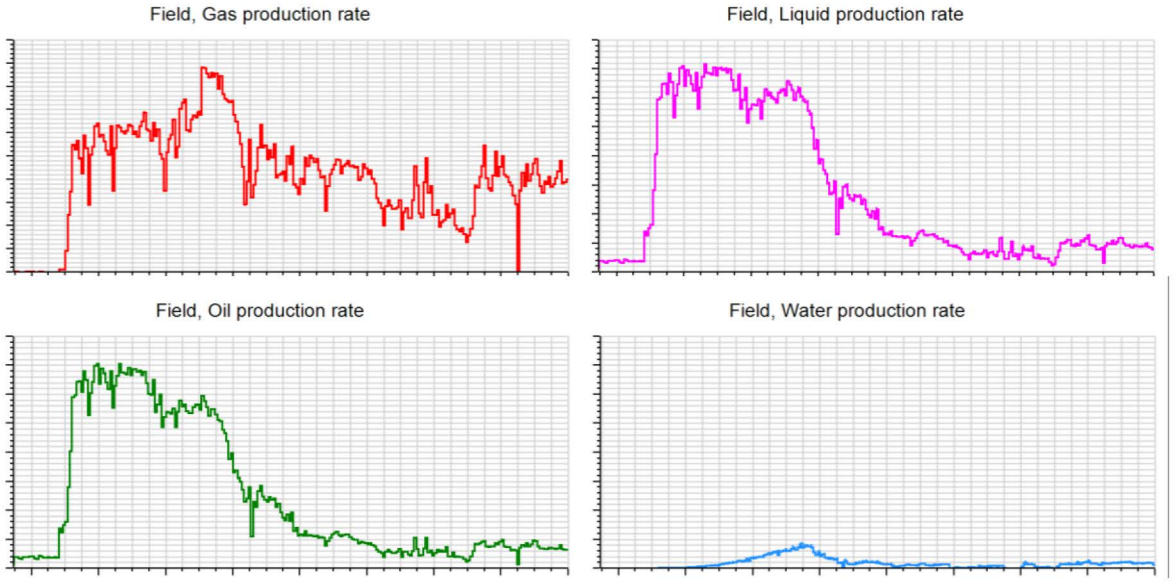


Figure 3—Comparison of History Match between Original Composition Dynamic Model versus the Converted CO_2 Dynamic Simulation Model.

CO2 Sequestration Cases Setup

A total CO_2 target injection rate per day of several millions of scf/d were set as the main objective for the injection process. This total CO_2 daily target injection rate was equally distributed within four injector wells. Likewise, the bottomhole injection pressure (BHIP), which is a key controlling factor in a CCS process, was constrained on function of the cap rock fracture gradient.

Table-1 shows the defined variables during the uncertainty analysis which was performed for evaluating the impact of those variables on the different CO_2 trapping mechanisms.

Table 1—Dynamic Model Case Description

Case	Description
Base Case	No alteration in grid and fluid properties. Pure CO_2 Stream
Well Pad Locations	Crestal vs Peripheral well Pad locations
Duration of CCS Process	Estimated total amount of injected CO_2 stream as well as Hydrocarbon recovery as part of the EOR process
CO_2 Stream	Pure CO_2 stream vs Impure CO_2 stream

Finally with the aim of optimizing the active wells productive life, a simulation code was generated to keep the producer wells opened until the injected CO2 arrived in the nearby wellbore areas when they will be shut in. This strategy also provided an initial input to define a P&A activity sequence so that the producer wells can be abandoned before the injected CO2 arrive to the wellbores. However, it is important to highlight that this strategy must be used as a complemented of the implemented CO2 monitoring plan.

Analysis of Results

The Base Case (BC) was considered with four horizontal wells on one cluster located on the crestal area of the reservoir. Likewise, the stream to be injected was considered as pure CO_2.

Simulation results indicate the injector wells were able to meet the case's daily injection target rate of CO_2 until the end of the simulation time. The average total amount of stored CO_2 during the simulation time was estimated by the order of 4 Mt p.a. Similarly, an increment of several hundreds of psia after the CO_2

injection process started until the end of the simulation was projected by the simulation model but it did not reach the defined capped reservoir pressure for avoiding cap rock integrity issues, Figure 4. On reference to the EOR process, a potential increment of several Bscf of gas and MMstb of oil was estimated by the end of the simulation model, Figure 5.

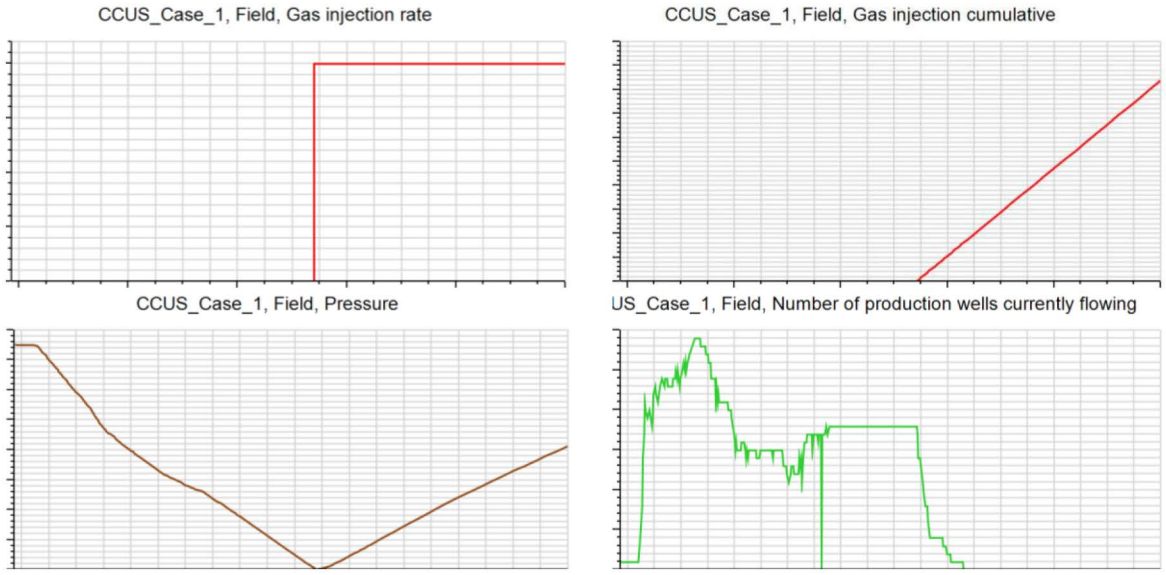


Figure 4—Base Case Field Level Results.

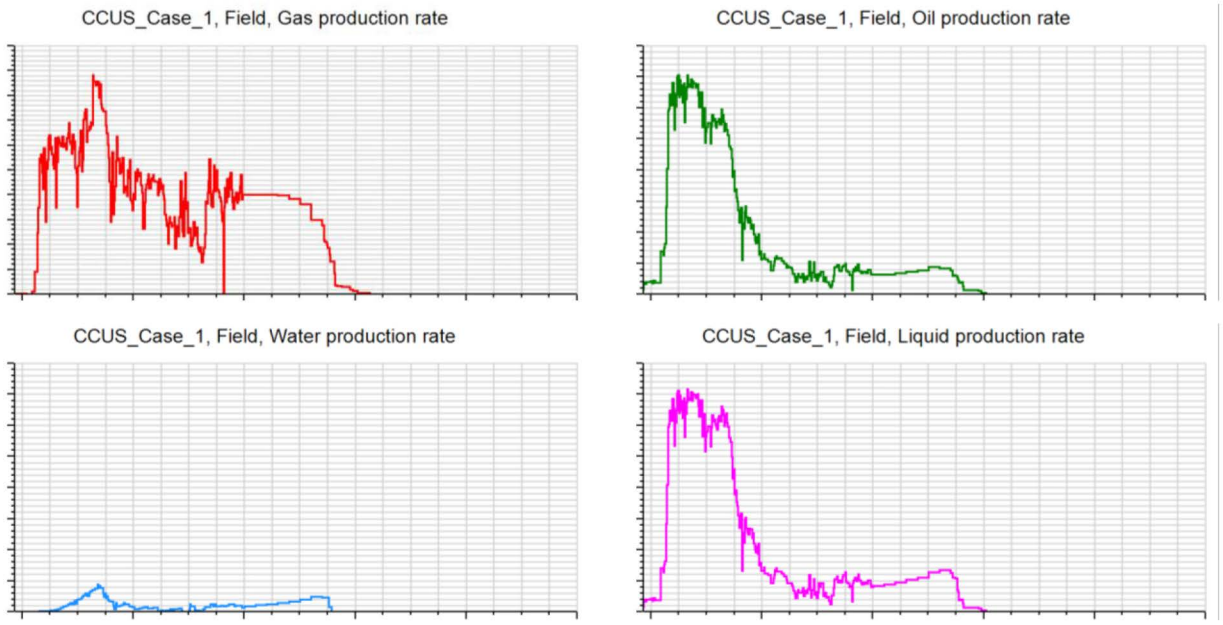


Figure 5—Base Case Field Level Production Rate Results.

Figure 6 shows the CO_2 plume migration at different points in time during the simulation run-time. As can be seen, the CO_2 plume migrates from the horizontal injector well areas towards the other sections of the reservoir, covering the crestal area but still not reaching the peripheral areas of the reservoir, especially the south-west section, by the end of the period of injection. This showed that optimization of the simulation case was required, by extending the CO_2 injection for a longer period.

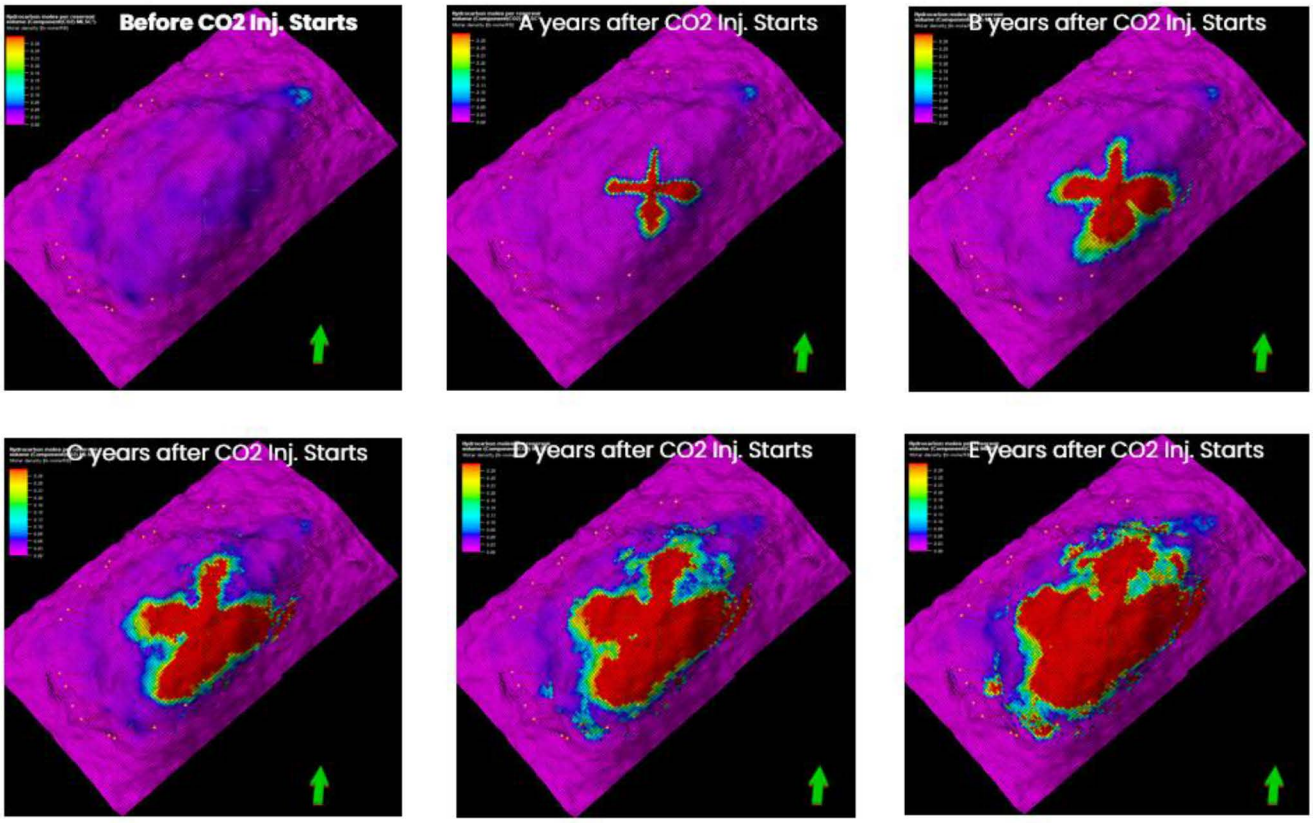


Figure 6—Base Case CO_2 Plume Migration

Well Pad Locations: Crestal vs Peripheral Well Pad Locations

This case was generated to examine the CO_2 sequestration process with injection into the south-west periphery area of the reservoir. Simulation model results showed that the CO_2 injector wells could maintain the target injection rate per well. The estimated total amount of stored CO_2 and the potential incremental on hydrocarbon production are the same as for BC. However, the average reservoir pressure at the end of the CO_2 stored process is slightly less than the value obtained from the BC due to the productive life of some producer wells is longer in this simulation case than in the BC.

Although simulation results were quite similar to the BC, there was an important difference regarding the CO_2 plume migration path. While the CO_2 plume migration occupied a wide reservoir section area in the crestal injection strategy, Figure 6, by comparison an important area to the north-east of the reservoir was still not reached by the CO_2 plume at the end of the simulation time in the south-west injection strategy, Figure 7. Therefore, the crestal injection strategy was selected as the most suitable option for moving forward with the sensitivity analysis on the other variables.

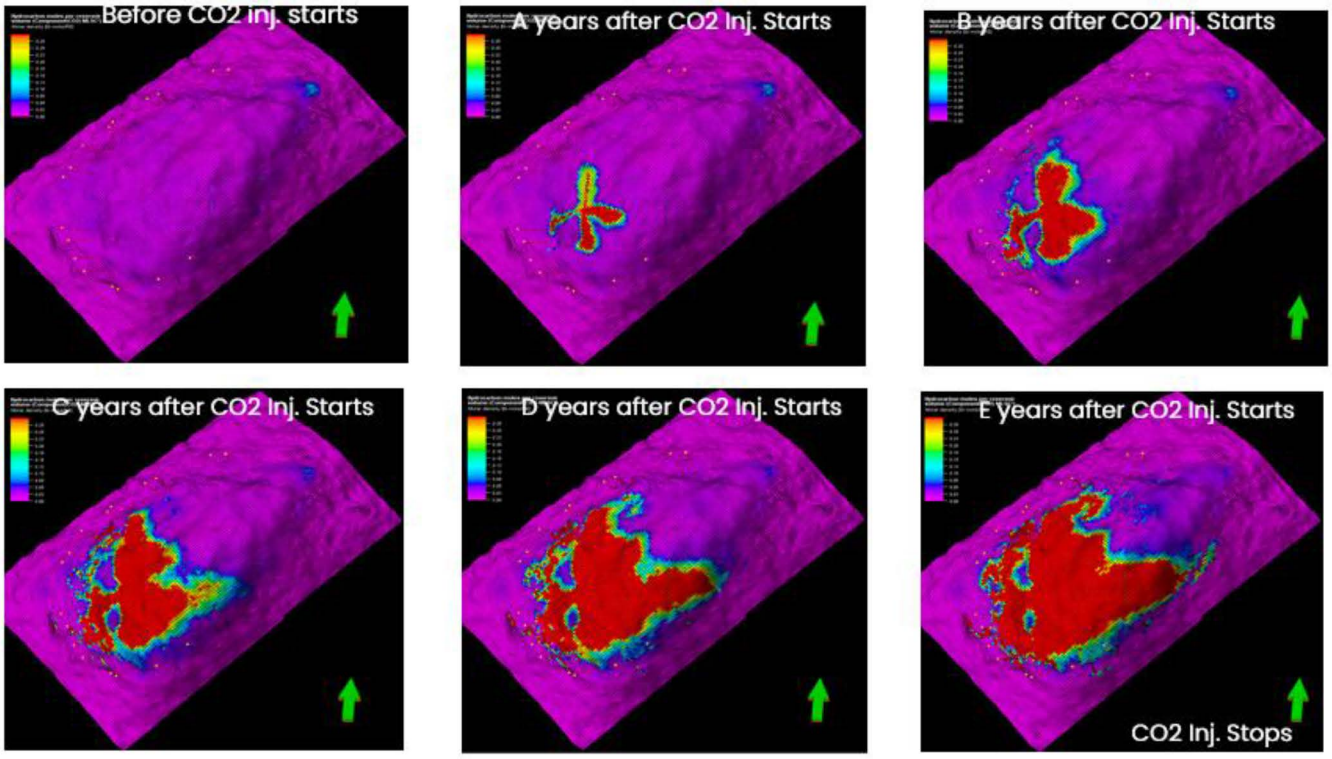


Figure 7—CO_2 Plume Migration – South-West Periphery Injection Strategy

Duration of CCS Process: Estimated total amount of injected CO2 stream as well as hydrocarbon recovery as part of the EOR process

Based on the previous results and with the aim of examining a longer duration CO_2 injection, which might yield an increased CO_2 storage volume, it was decided to keep the same dynamic model assumptions. However, the CO_2 injection process was performed until the average field reservoir pressure value reached the defined safety limit percentage of the initial reservoir pressure. Once the CO_2 injection process stop, the simulation model was run for several more years for assessing the plume migration as well as the reservoir pressure equilibrium process.

Simulation results indicate the injector wells were able to meet the case's daily injection target rate of CO_2 for a longer period of time when comparing with the initial BC. However, three (3) out of the four (4) injector wells reached the maximum allowable BHIP before the initial reservoir pressure reaches the defined safety limit value. The total amount of stored CO_2 was increased by approximately **62%** in comparison to the initial BC whereas the incremental production results of this case were the same as the incremental production results from BC, Figure 8.

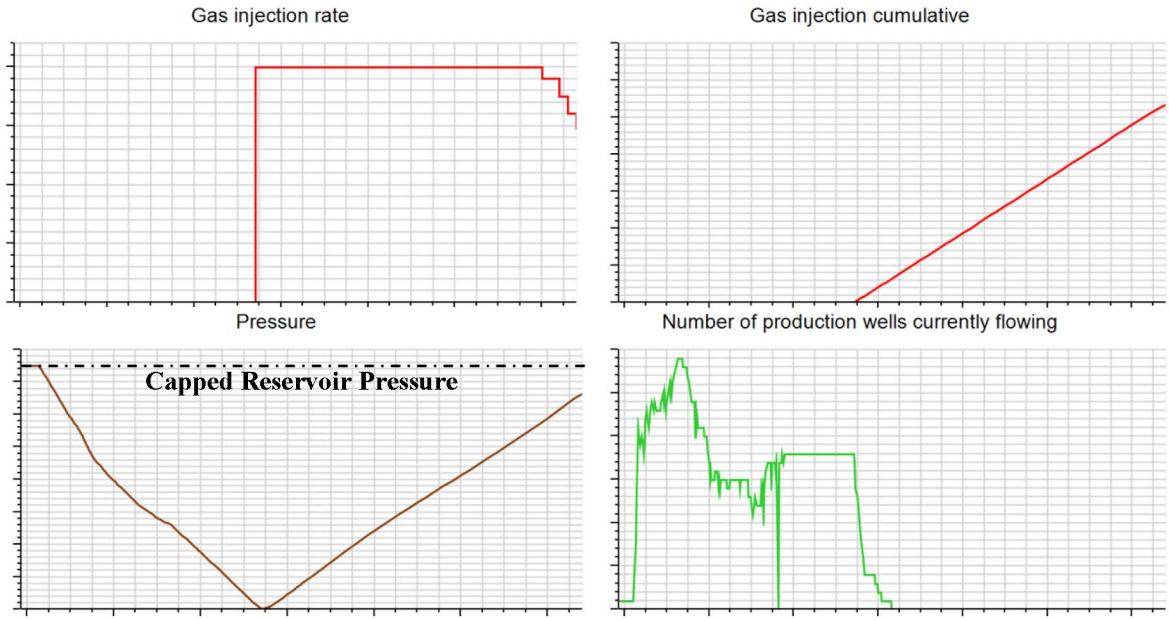


Figure 8—Base Case Field Level Results – CO_2 Injection Time Optimization

Figure 9 shows the plume migration until the time at which the CO_2 injection stopped. Due to the larger quantity of CO_2 injected in this case comparing with the BC, the CO_2 migrated to a wider section of the reservoir area, covering a significantly greater portion of the reservoir in comparison to results of BC.

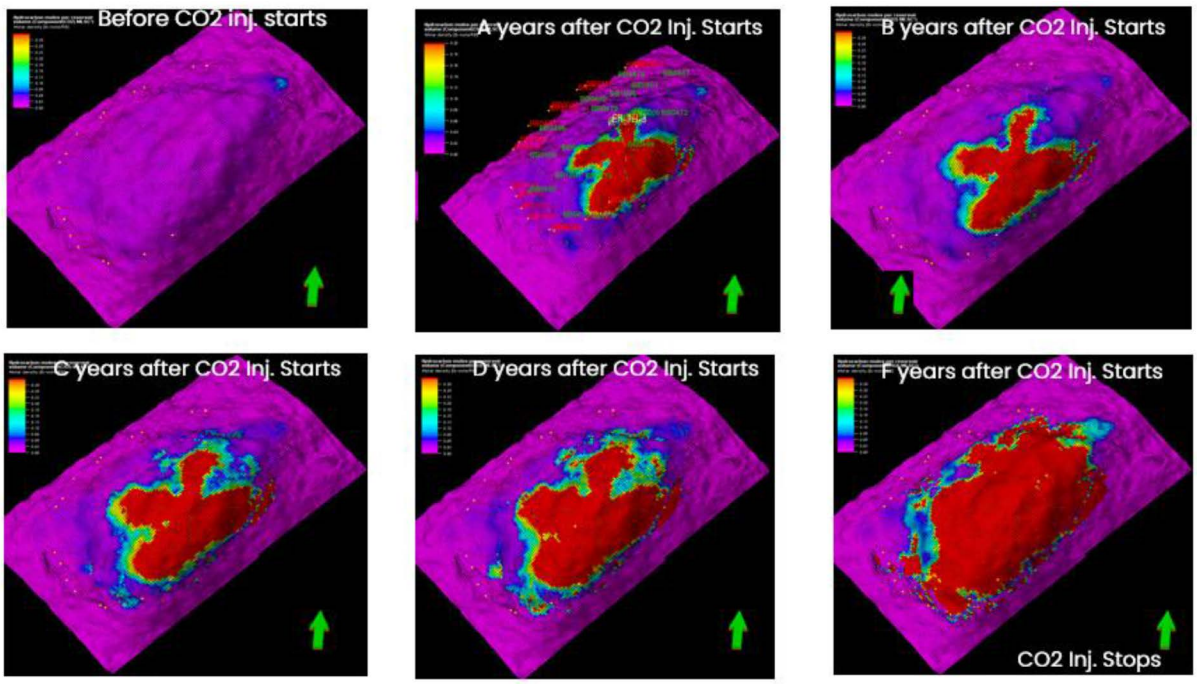


Figure 9—Base Case CO_2 Plume Migration _ CO_2 Injection Time Optimization I need to sanitize it.

Figure 10 depicts the average reservoir pressure during the complete simulation time. Its value declined by several dozens of psia as a result of the equilibrium process due to reservoir fluid redistribution.

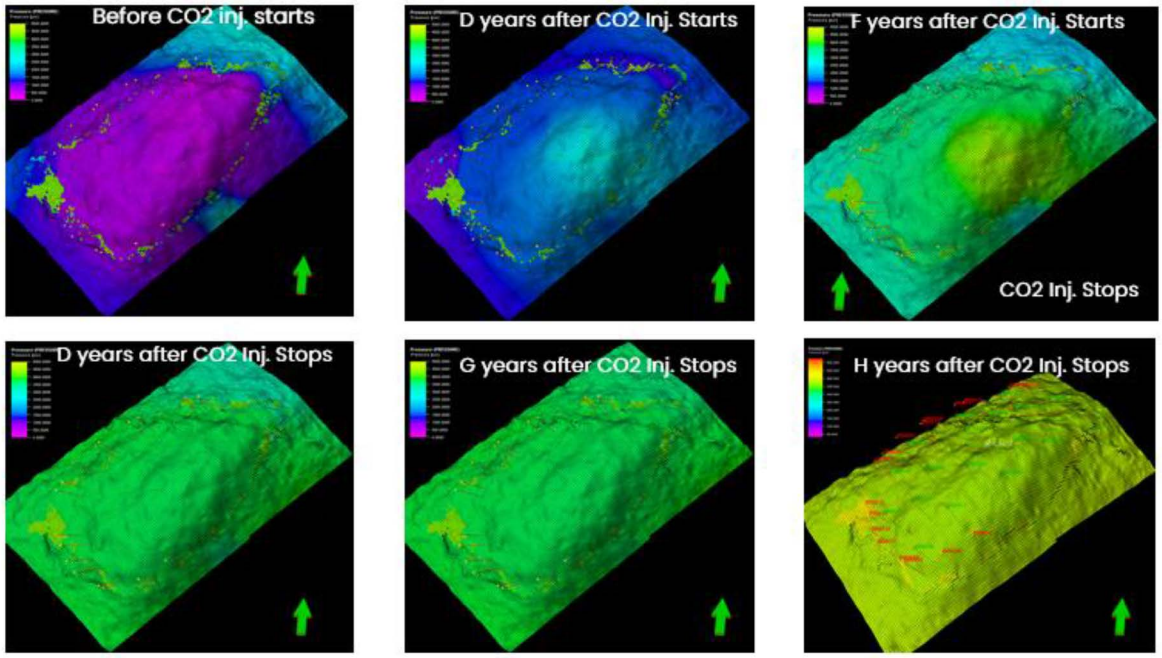


Figure 10—Average Reservoir Pressure Over Time, Reservoir Equilibrium Process CO_2 Injection Time Optimization

CO2 Stream: Impact of the Impurities on the CCS Process

Crestal Injection Strategy was used as basis for evaluating the impact of impure CO_2 stream injection on the CCS process.

Dynamic simulation model results showed that the impure CO_2 composition did not have any impact on either the total injected gas volume or incremental production but did increase the average simulated reservoir pressure by around 100 psia at the end of the simulation time when comparing against the CO_2 Injection Time Optimization Case. This is mainly driven by different solubility of the impurity on the injection stream. On the other hand, despite the total injected CO_2 gas stream cumulative volume being the same in both cases, there was a slight reduction in the quantity of CO_2 stored due to the presence of impurities in the CO_2 injection stream, Figure 11.

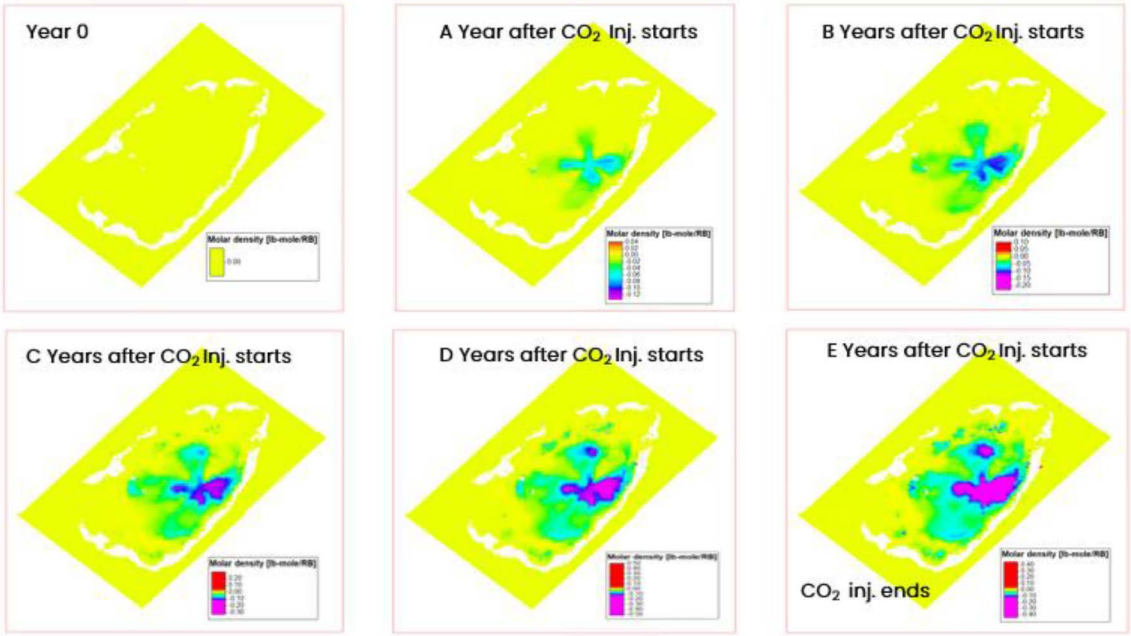


Figure 11—Reservoir Maps representing the difference of CO_2 Molar Density between cases with and without CO_2 impurities

Summary of Dynamic Simulation Model Results

- There are no major differences between the cases in the potential incremental hydrocarbon production.
- There is no major difference in the stored CO_2 volume between the crestal and peripheral injection strategy scenarios.
- The CO_2 plume migration covering a more extended area of the reservoir in the crestal injection strategy case compared to the south-west periphery injection strategy case.
- The impure CO_2 stream injection case lead to a slightly reduction in the quantity of stored CO_2 when the injection rate control is CO_2 stream volumetric flow rate, due to the presence of the impurities.

Geomechanics

Geomechanical analysis was carried out to understand the geomechanical setting across subject storage reservoir and assess potential risks associated with the reservoir and caprock integrity. Geomechanical models were built for key wells based on data richness and spatial location in the field. A normal stress setting was observed across the formations of interests as shown in Figure 12. The model was established at original reservoir pressure condition and depletion-injection were applied subsequently along with suitable stress path to update horizontal stresses to represent accurate reservoir condition. Reservoir pressure at the start of CO2 injection was expected to be well below 0.5 psi/ft (significant depletion due to hydrocarbon production) and max planned reservoir pressure was expected to be less than original reservoir pressure. Due to very low reservoir pressure expected at the start of CO2 injection, the possibility of pore collapse was assessed with the help of regional data from nearby fields. It was determined that with the given rock mechanical properties, risk of pore collapse is low even at the lowest expected reservoir pressure; it is expected to be well within elastic zone and hence a simple poro-elastic rebound of stresses assumed for injection scenario can be followed (Figure 13).

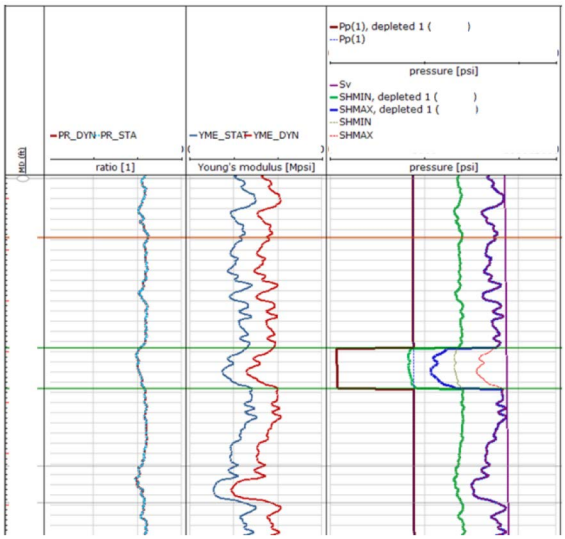


Figure 12—Rock mechanical properties and stress profiles across formations of interest.

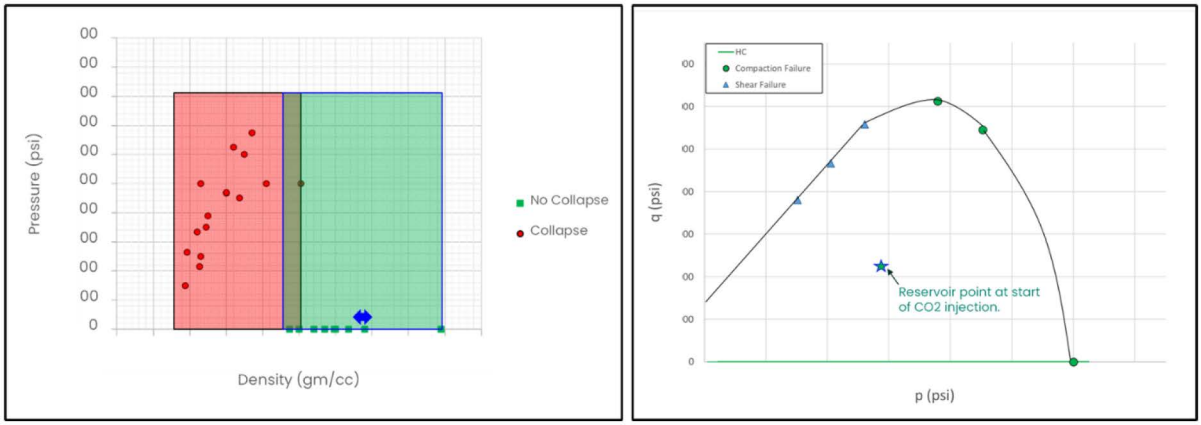


Figure 13—Hydrostatic test result summary, pore collapse risk plotted against density. Blue arrow bar shows density values noted across target reservoir (left). Rock failure envelope compared to reservoir condition at the start of CO_2 injection (right).

With the Geomechanical models, the eventual objective was to assess instability of existing faults and fractures due to changes in pressure and/or temperature and if any chance of potential tensile breach of caprock exists. In the current scenario, apart from effects of depletion and injection, impact of temperature changes was expected on reservoir-caprock system integrity due to significantly cooler injection fluid temperature at the bottomhole. Similar to depletion/injection induced poroelastic changes on horizontal stresses, when the temperature increases or decreases, the materials will expand or contract, this would increase or decrease the field stresses. In case any cooling happens because of fluid injection, horizontal stresses will also reduce. The change in horizontal stresses due to temperature changes were approximated by Perkins and Gonzalez and depends upon magnitude of temperature change and elastic properties of the rock. Modified horizontal stresses incorporating changes in pressure and temperature can be written as below:

$$S_{hmin,new} = S_{hmin,initial} + \Delta S_P + \Delta S_T$$
$$S_{Hmax,new} = S_{Hmax,initial} + \Delta S_P + \Delta S_T$$

Where ΔS_P is change in stress due to pressure changes and addressed using stress path factor and ΔS_T is change in stress due to temperature changes and calculated using analytical solution following Perkins and Gonzalez. Thermal stresses (ΔS_T) can be calculated using following equation:

$$\Delta S_T = \frac{\beta E \Delta T}{(1-\nu)}$$

(after Perkins & Gonzalez, 1984, Hojung, J., 2018, Søreide, O.K., 2014)

β: Thermal Expansion Coefficient
E: Young's Modulus
ΔT: Change in Temperature
ν: Poisson's Ratio

Well performance modelling was conducted in order to capture the transient behavior of CO2 during injection, which provides expected bottomhole temperature of injected CO2 for given composition and flow rates. Two scenarios of injected CO2 temperatures were analyzed to understand impact on geomechanical behavior of reservoir-caprock system. The CO2 temperature derived from well modeling is expected to be at the injection point, however, to consider the impact of temperature on stresses, temperature front evolution across reservoir and caprock is required. Based on analogue studies, where temperature front evolution was modeled, it was recognized that thermal effects extend tens of meters into the caprock and thermal stresses can be an important factor for determining caprock integrity. Geomechanical analysis performed with consideration of temperature effects, which suggested high risk of caprock integrity failure. The magnitude of thermal stresses at given amount of formation cooling and rock mechanical properties were expected to be very high in magnitude, which results in substantial reduction of horizontal stresses to a level significant enough to cause tensile failure (Figure 3). Additionally, critically stressed fracture (CSF) analysis was performed for multiple set of potential faults/fractures across reservoir-caprock system. With reduced horizontal stresses, the effective normal stress on fault planes reduces significantly and almost every possible set of fault/fracture is expected to get critically stressed, which may result in shear breach of the cap-rock (Figure 14). It is important to note here that geomechanical effects of pressure and temperature changes on horizontal stresses were incorporated with analytical modelling and using analogue values of certain rock mechanical parameters. Also, the effect of any potential rock mechanical property changes due to cooling and/or rock-CO2 interaction was not understood. Performing dynamic geomechanical modelling incorporating true set of faults and fractures and any potential changes in rock mechanical properties may further help to reduce prediction uncertainties.

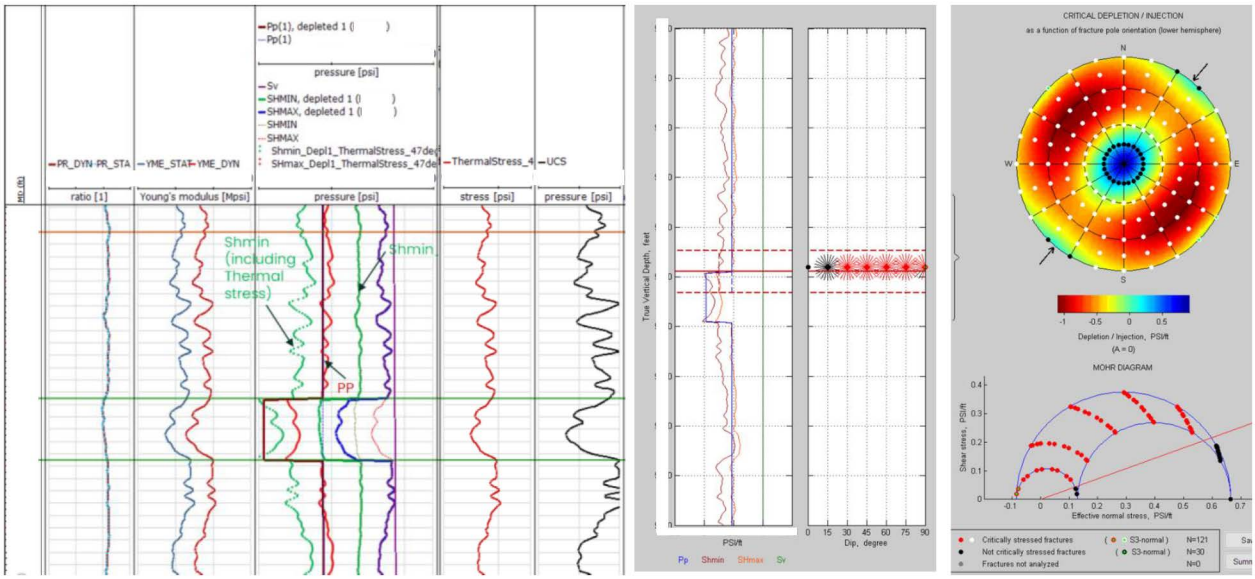


Figure 14—Geomechanical model displaying updated stress profiles incorporating thermal stresses (left). Critically stressed fracture analysis showing most of the fault orientations getting critically stressed at stress magnitudes with thermal effects (right).

Injection Well Design Options

CO_2 injector well designs targeting a depleted gas reservoir were prepared based upon the requirements of meeting the CO_2 injection volume and the envisaged injection rate.

Well Trajectory

The proposed injector wells were planned to be horizontal across the reservoir section. The main driving points in designing the proposed injector wells' trajectories were selection of a competent formation for the kick-off point (KOP), controlled dog-leg severity (DLS) across unstable shale formations and the proposed landing point of each of the trajectory was designed to be at the upper depth point of the target window across the reservoir section and the well TD criteria was determined by the last depth point of the target window across the reservoir section.

Injector Wells Design Philosophy

The basis upon which the CO_2 injector wells are designed are as below.

- The requirements of CO_2 injection – ability to withstand the injection and shut-in planned and unplanned/failure loads.
- The planned wells' design able to cope with a range of CO_2 arrival rates within the limits of the capture plant and surface equipment.
- The robustness of the well design for injection and avoid any leak path through the well.
- Completion design considers the presence of CO_2, water, hydrocarbons and H_2S.
- The ability to place multiple independent permanent barriers/seals/cement plugs for permanently securing the storage of CO_2, post targeted injection of CO_2 volume.
- The well design is based upon the US EPA CO_2 Injector Class VI well construction guidelines and the completions string is designed as per the NORSOK D010 standard version IV (2021) standard.

Reservoir Pressure and Hydrate Formation Considerations

To represent the the CO_2 injectivity performance over the injection period from planned start of injection to the planned end of injection, several time-steps were defined. Reservoir dynamic modelling data such as the reservoir pressure, bottomhole pressure and different injection rates were used to generate IPR (Inflow Performance Rates) for those time-steps. Well performance modelling was conducted, on an industry certified software, to capture the transient behaviour of CO_2 during injection and based upon the CO_2 injection rates, derived from reservoir dynamic modelling, bottomhole injection pressure and temperature were defined for each time step. These reservoir pressures and injection temperatures, for each of the several cases were considered to model the injection loads on the completion string.

The risk of hydrate formation was evaluated using fixed injection rates as per the reservoir dynamic modelling, during the early stage of injection when the reservoir pressure would be depleted and considering minimal water to the CO_2 gas composition. Phase and hydrate envelopes of high and low purity CO_2 injectate were generated, showing no imminent hydrate risk, under the present operating conditions.

Material Selection

Based on the expected reservoir fluids and the CO_2 injectate components' molar %, a detailed corrosion analysis was studied taking into consideration the partial pressure of H_2S, pH, water content and maximum chloride concentration. The applicability of materials which fall outside of our understanding of the anticipated conditions and the guidelines specified within the standards would require material testing across the range of compositions and conditions relevant to this application. Corrosion can occur in the injector wells under various conditions during injection and shut-in conditions; production casing, completions tubing and equipment, which are flow-wetted and in direct contact of CO_2, oxygen corrosion, stagnant reservoir fluids and under varying pressures and temperatures and flow velocities, are at a risk of low pH passivation and cracking, general pitting and corrosion, and oxygen crevice corrosion under shut-in conditions.

25Cr Duplex Stainless-Steel material was recommended for injection well materials which are flow wetted pressure barriers. Low temperature HNBR (Hydrogenated acrylonitrile butadiene rubber) was recommended for the elastomer seals of various completion components.

Well Schematic

The proposed injectors' wells were planned vertical in the surface and intermediate sections. The kickoff and build to lateral were proposed in the production section, with the horizontal section across the reservoir, as an open hole, as shown in below Figure 15.

According to The United States Environmental Protection Agency, criteria, and standards applicable to Class VI (CO_2 Injection Wells) well construction requirements, 40 CFR 146.86, point b-(3), at least one long casing string must extend to the injection zone and must be cemented to surface, and hence accordingly the planned production casing is extending inside the target injection reservoir section for the proposed CO_2 injector wells.

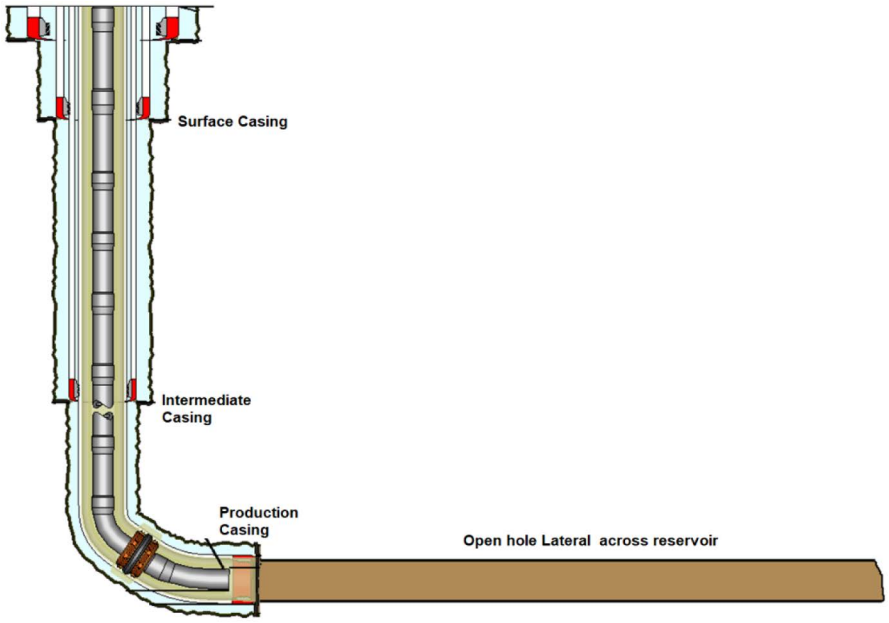


Figure 15—Proposed Injectors well schematic

Tubing Stress Analysis

Various injection, shut-in and failure loads were simulated in an industry recognized software package, to ensure the robustness and integrity of the proposed injectors' well design, as tabulated in below Table-2

Table 2—Simulated Load Cases

Load Case	Tubing Pressure (psi)	Annulus Pressure (psi)	Tubing Fluid
CO_2 injection @ various stipulated injection rates for various sets of time periods	Various reservoir pressure sets determined from reservoir dynamic modelling and geomechanics study at stipulated perforation depth	0	CO_2
Cold and Hot shut-in for elongated and short time periods	Various reservoir pressure sets at stipulated perforation depth	0	CO_2
Leaking Choke (Failure Load Case)	Various reservoir pressure sets at stipulated perforation depth	0	CO_2
Cold Blowout -73^{0}C at the surface (Failure Load Case)	Maximum reservoir pressure expected from the model at stipulated perforation depth	0	CO_2
Tubing Leak scenarios during injection and shut-in periods	Maximum reservoir pressure expected from the model at stipulated perforation depth	Leak Surface Pressure from individual injection and shut-in load cases	CO_2

All the load cases were also simulated on the proposed completions packer and were successfully within the packer loads envelope. Annular Fluid Expansion sensitivity was also carried out, successfully, for the different injection loads related to different injection temperatures and reservoir pressure sets.

Surface Facilities Options

A high-level technical definition and AACEi Class 4 cost estimates were developed as part of a feasibility study identifying surface facilities requirements for onshore CCS deployment1 in the subject storage reservoir. Figure 16 shows the entire value chain blocks for CCUS development.

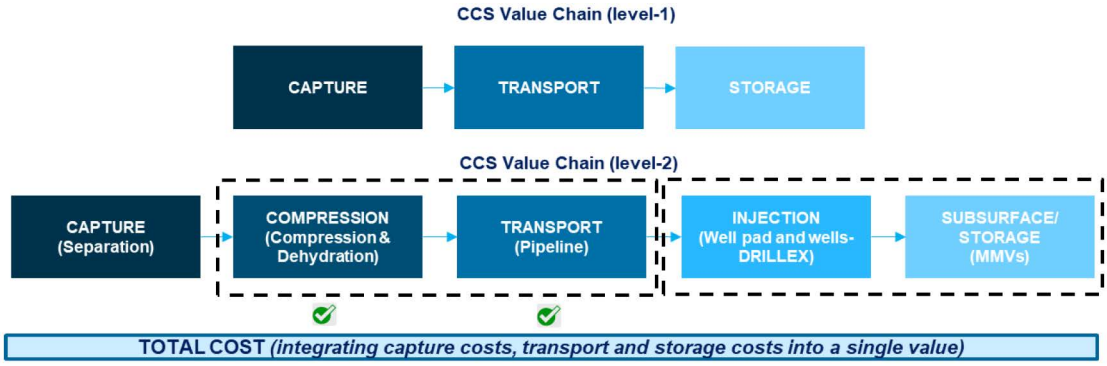


Figure 16—CCS value chain blocks

The surface facilities definition covered the process of CO2 compression, dehydration, transport via pipeline from capture source to the final stage pumping near injection site.

The subject reservoir had a higher bottom hole pressure (BHP) resulting in relatively higher WHIP and up to five CO2 injectors (injection wells) were envisaged. In addition, at the final injection site a HP injection stage / Pumping was envisaged after about 3½ years from start of operations.

The CO2 was proposed to be sourced from CO2 capture plants planned located in an Industrial area. The surface facilities for compression and dehydration will be located close to the CO2 sources to collect low pressure CO2 at near atmospheric conditions. The wet CO2 would be compressed in a 4-stage LP Compressor unit, dried using glycol-based gas dehydration unit and further compressed in a single stage of MP compressor prior to entering a long-distance CO2 onshore pipeline.

Figure 17 presents a block flow diagram level view of the development scheme.

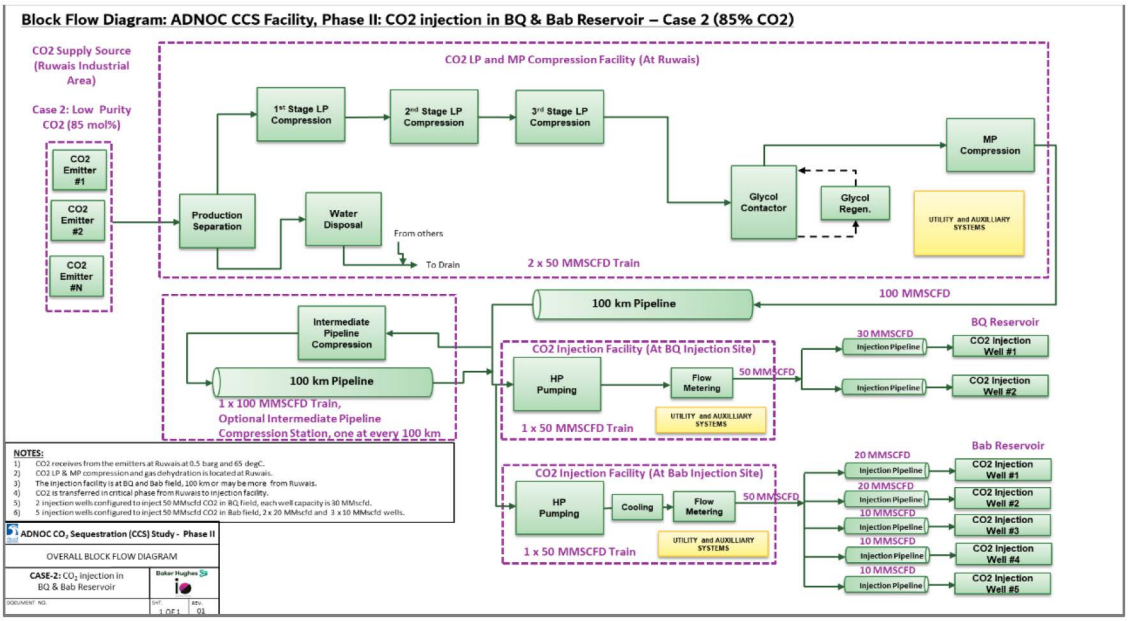


Figure 17—Block Flow Diagram for Surface Facilities scheme

The central facility designed for about 100 MMSCFD CO2 injection and the final injection facilities located near injection site will be in 2 X 50% trains configuration (i.e. each train of 50 MMSCFD capacity). The FWHIP and injection temperature required for the CO2 injectors at well pad is achieved by a final HP pumping followed by an air-cooling step in a facility located near the injection site.

Drying of CO2 allows use of Carbon steel material for downstream compression units and pipeline. The CO2 pipeline will operate in dense phase to minimize the pipeline diameter and further drive down the pipeline cost. The technical definition was supplemented by including high level materials assessment, utility and support systems including power, environmental and safety risk assessment and review of safety and surface facilities monitoring requirements.

The total Installed Cost (CAPEX) for Compression, Dehydration and Pipeline, OPEX, ABEX and facilities phasing inputs were used to perform economic assessment. The techno-commercial evaluations considered the following range of scenarios and cases:

- Source emitters type
- Source emitter locations
- CO2 Capture technologies
- Various CO2 capture rates and volumes of CO2
- Potential CO2 storage sites/reservoirs
- CO2 pricing and CCS models
- CCS and CCUS integrated strategies and Environmental goals/vision plans

The surface facilities design in largely influenced by the CO2 composition and corresponding CO2 phase envelope. During conceptual stage the impact of CO2 composition and impurities was studied as part of a detailed literature review and by accounting for three different CO2 injection specifications in the surface facilities assessment. The type of CO2 emitter, its location, the capture technology used, the CO2 capture rates, CO2 pricing business model and any long-term environmental goals will all influence the decisions around such a large-scale CCS project. When moving forward to the Identify stage, these technical, commercial, and strategic framing topics were recommended to be considered and complemented by learnings from this current study.

Existing Wells Integrity Assessment

High level description on workflow for existing well integrity assessment is described below.

A request has been raised to undertake a review of depleted Gas reservoir to define the feasibility for CCS, and required steps to mitigate risks to realize this objectives in a safe and economical manner. Part of this feasibility is to define the well integrity risks and well construction material requirements for undertaking this project.

During CCS, the injection of CO2 will result in a number of interactions which will influence material selection and pre-existing well integrity, this includes: re-pressurization of the reservoir, dehydration and cooling of near well bore, re-condensation of water as pressures increase, the pH and composition of waters due to condensed water dilution and CO2 dissolution and finally the plume migration through the reservoir and through any seal failures such as communicating faults and communicating wellbores and annuli. In total, 250 pre-existing wells are present in the field.

There are several well types, the current condition and integrity risks for which must be understood for CCS. This includes previously abandoned wells completed into and transitioning the target reservoir, active production wells completed into and transitioning the target reservoir, monitoring wells and the CO2 injection wells.

The status and requirements of pre-existing wells is understood by reviewing historical materials used, including cement types, as well as understanding the condition of the cement in place through cement-bond-logs (CBL) and the type of cement used, as well as the historical contacting fluid compositions and

the temperature and pressure of the exposure. Such a review would require the use of the below workflow, Figure 18:

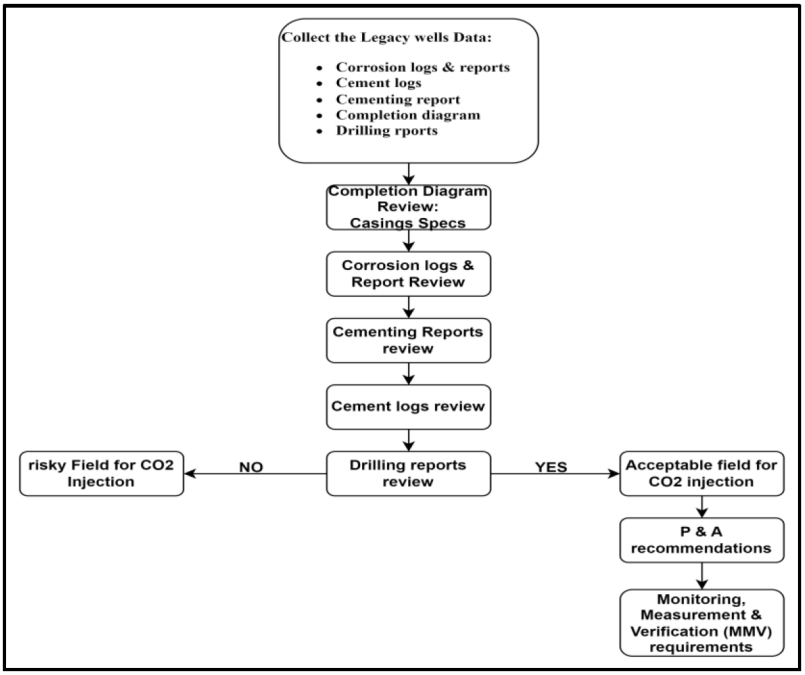


Figure 18—Well integrity workflow

The pre-existing production wells and production wells casings completed to lower horizons are completed of L80 grade compliant carbon steel, this would be subject to significant corrosion once the CO2 plume arrives, and even more rapid corrosion once the pressure is sufficient for condensed water drop-out to occur, this is particularly relevant for the wells in the immediate proximity of the injection wells. These wells will see a significant through-put of CO2 and H2S anywhere gaps exist.

A review of the cement types used indicates that the application of class G cements would be unsuitable, both geochemical modelling and laboratory tests have demonstrated that in a high CO2 environment theses cements would swell and crack, and as such the sealing nature of this material would be lost, either directly or against contacting surfaces such as the formation of the casing wall. Modelling has demonstrated that although these cements would be competent with the in-situ fluid compositions and conditions, It is the transition from the current fluids to a high CO2 fluid which will drive swelling reactions, which will induce cracking, as shown in below Figure 19.

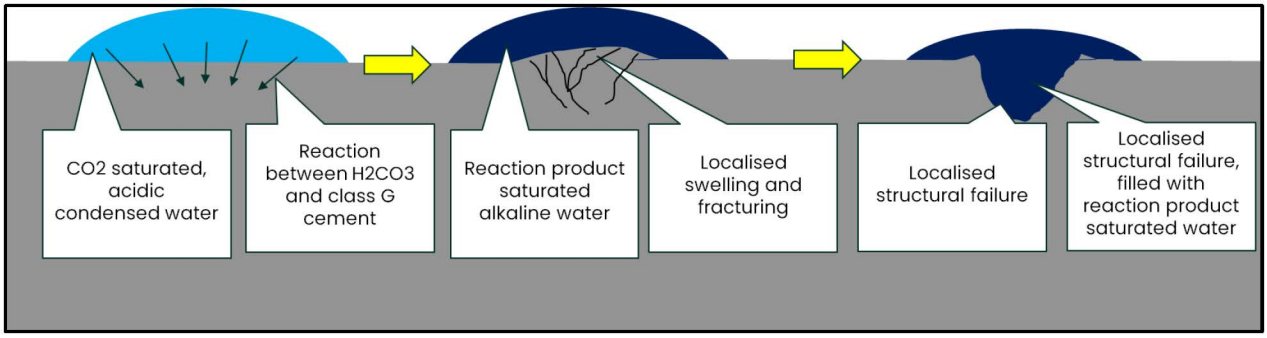


Figure 19—Sequence of cement swelling and fracturing.

The total number of pre-existing deeper wells to be remediated for the reservoir is in excess of 150, Out of these wells, it was identified that one third of them (mostly wells intersecting both the deeper and targeted reservoirs; a few wells passing only to the targeted reservoir). These identified wells require intervention prior to the commencement of CO2 injection with respect to the following workflow, Figure 20.

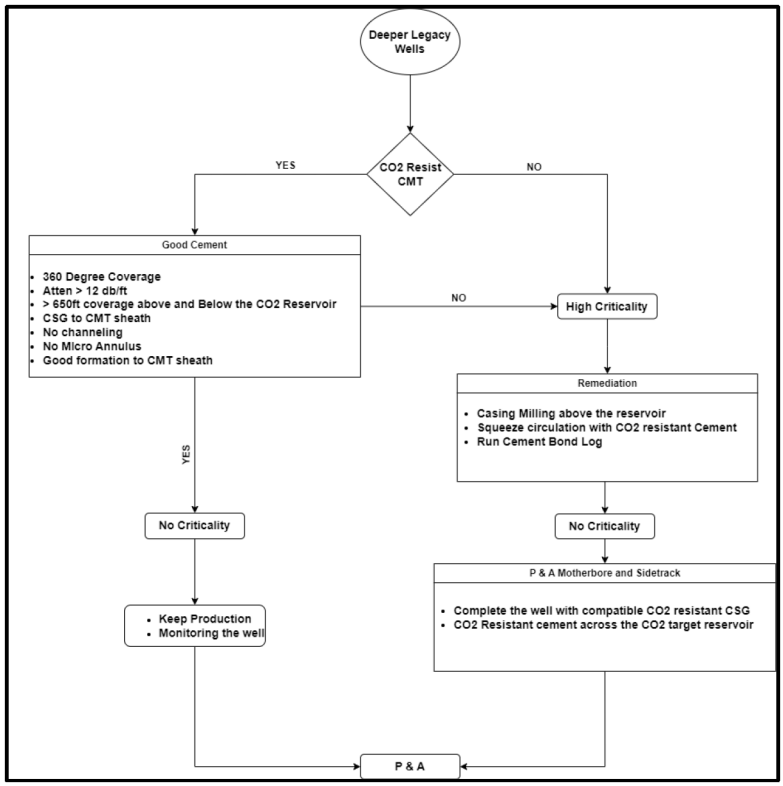


Figure 20—Transition deeper wells passing the target reservoir remediation workflow.

The pre-existing wells from targeted reservoir would have to undergo P & A or work over prior to the CO2 injection as per standard P & A procedures, however this must ensure CO2 resistant barriers (cement, elastomers and exposed metallurgies) are present within the wells. The following workflow, Figure 21, has been established to ensure the appropriate requirements are met.

For the injection wells it has been determined that under normal injection of a dehydrated CO2 stream, with no liquid water present, no specific material requirement exists, however under a shut-in condition or if the dehydration of injected CO2 is out of specification, and liquid water, even in trace amounts may be present, a significant risk of corrosion and sulfide stress cracking to non-CRA flow wetted materials may exist.

For CRA materials there is a potential for sulfide stress cracking for any metallurgy with a minimum allowable pH rating (in accordance with NACE MR0175/ISO15156) of greater than 3 and/or a partial pressure limit for H2S of less than 2.5 psi. This results in a recommendation for all flow wetted metallurgies to be of 25Cr (Super Duplex) construction or nickel chrome alloys. The non-flow wetted casing (secondary pressure barrier) may be of L80 grade compliant carbon steel construction.

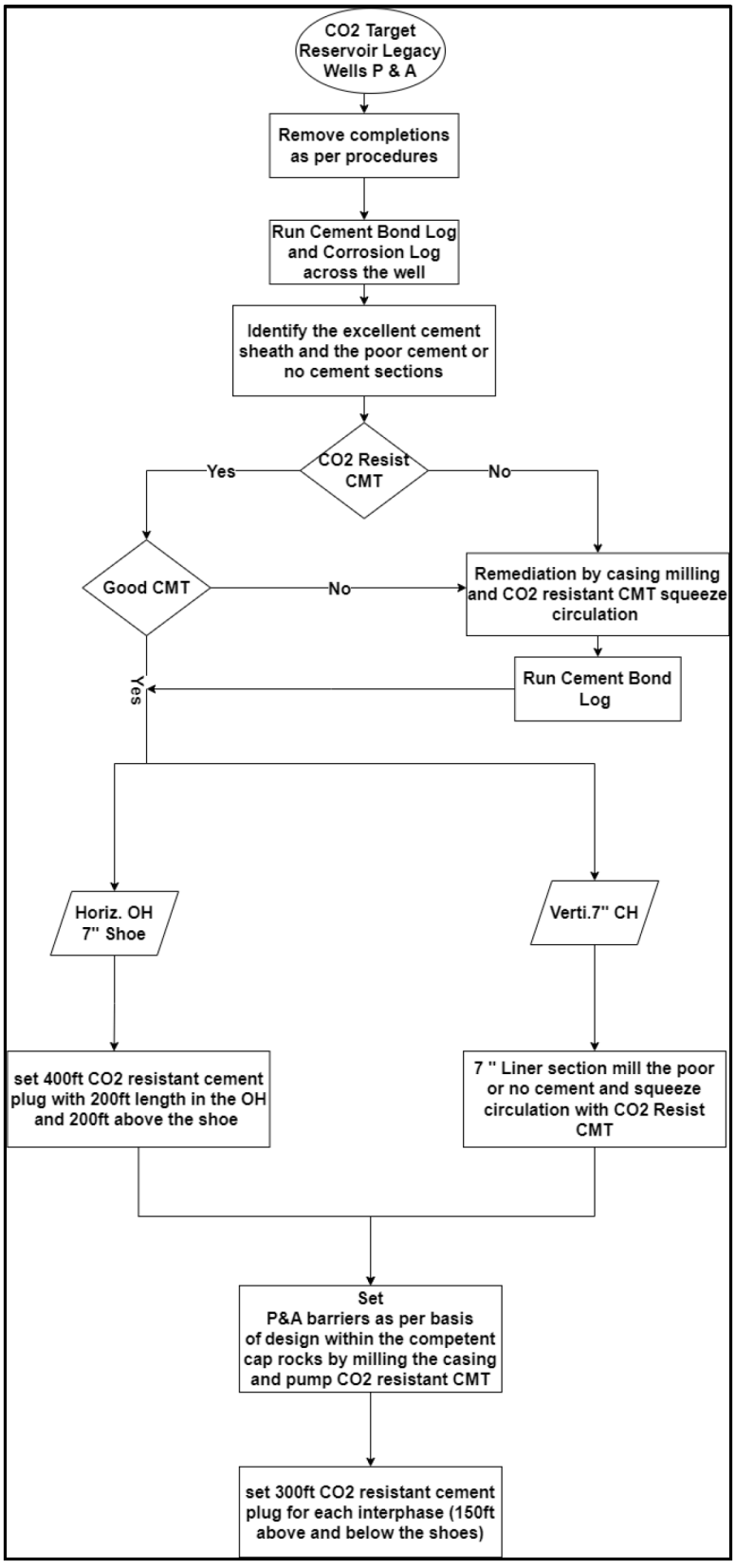


Figure 21—Target reservoir wells P&A workflow

For selection of elastomeric and anti-extrusion ring materials, it is considered that the material must be able to retain properties at low temperatures, due to Joules Thompson cooling under gas phase CO2 injection, and must also be CO2 and H2S resistant. Elastomers must also be rapid-gas-decompression resistant, for this purpose low temperature grades of HNBR would be required, though standard anti extrusion rings of PTFE or PEEK would be suitable.

Similar studies, undertaken by other operators to understand risk and material requirement on their assets in the UK North Sea, present a less conservative view on cement and metallurgy requirements. Indicating that the use of Portland cement and 13Cr metallurgies should be suitable. What the study fails to highlight is the presence or absence of H2S, the partial pressures of which are another driving factor in the selection of materials for this project Additionally the understanding of fluid interactions is more complete with the current workflows than it has historically been, and advancements in software allows us to better understand the potential for water displacement, evaporation and re-condensation. As such the study referenced here does not identify that the injected CO2 will begin to redistribute the water it has evaporated, and that the quantity of water it will deposit would be significant enough to allow reactive films to form on all contacted surfaces in the presence of significant CO2 and H2S. Comparisons with other CCS studies show less conservative conclusions, however the conditions considered are also less conservative – no condensed water or H2S.

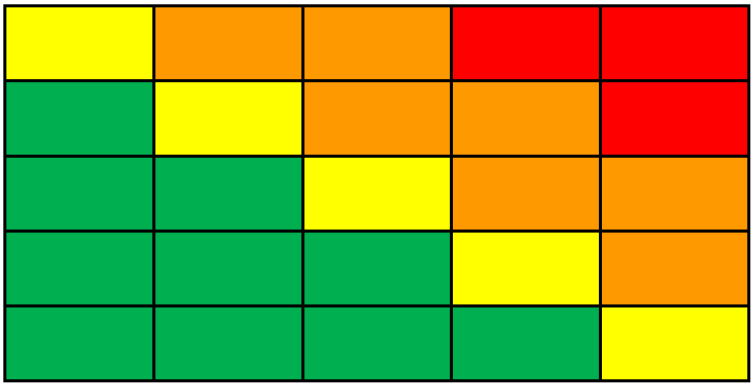
Additionally, we must recognize that CO2 EOR injection wells (for miscible gas injection) should not be considered as directly analogous to CCS injection wells and pre-existing completions. CO2 EOR injection wells are relatively short-term installations intended to provide displacement of in-situ fluids and dissolution of CO2 into them. It is likely that consideration has not been given to the effects of condensed water as the anticipated pressure rise, if there is one, is not likely to be significant, therefore re-condensation of evaporated formation water is not an issue. CCS injection wells are designed with long-term storage and significant reservoir pressure increase (up to the limit of the underlying and overlying mechanical formation integrity), which will lead to significant condensed water drop out (the source of water can be either formation water, even if its residual, or part of injected CO2 if out of spec).

The review of the Integrity risks for undertaking CCS in the field has established that injection wells and plume exposed pre-existing production wells would need to be of 25Cr or nickel chrome alloy construction with CO2 resistant cements in place for all surfaces that will directly contact the CO2 injected into the reservoir, the partial pressure of H2S in a low pH environment which is anticipated precludes selection of any lesser/lower grade material (flow wetted pressure barriers including both casing and cement).

Table 3—Risk Rating Wells

	Consequences				
	Very low impact	Low impact	Medium impact	High impact	Very high impact
	1	2	3	4	5
People	No forseeable injury, no health risk	Personal injuries/ illnesses involving first aid treatment, no health risk	Lost Time IncidenUReportable Incident Personal injuries/ illnesses	Personal injuries/ illnesses including loss of life, major injuries (broken	Single or Multiple Fatalities
Envorinmental Damage	Minor unpermitted discharge (<0.5t). Negligable impactr on the environment. On-site release of non toxic materials <208L (<55 gal)	On-site release of toxic material presents an acute health risk. On-site release of non toxic materials <208L (<55 gal)	On-site release of toxic material presents an acute health risk. Off-site release of toxic material impacts the environment. Off-site release of non-toxic material >208 L (>55 Gal) Environmental damage affecting nearby community Fire handled by local staff	Major unpermitted discharge (high toxicity chemical, S - 251oil). Off-site release of toxic material presents an acute health risk. Explosions and/ or fires requiring outside assistance. Radiation releases. Chronic environmental damage affecting nearby communiry.	Uncontrolled release of oil Widespread environmental damage affects public areas
Asset Damage	Local impact - no disruptions to operations	Brief disruption of function or operation to effect repair. Minor property or equipment damage from $500 to $10,000.	Local loss of function affecting operation Business interruption, property loss or damage in the range of $10,000 to $250,000	Business interruption, property loss or damage in the range of $250,000 to $1,000,000. Major damage - facility shutdown for up to 1 week for repair	Total loss of facility and extensive localdamage Business interruption, property loss or damage exceeding $1,000,000.
Reputation Damage	Notify regulator, no further regulatory dialog	Single breach of regulations.Low leveldialogue with regulator.	Repeated breach of regulations Incident investigation by regulator.Potential prosecution.	Extended breach of regulations Prosecution by regulator.Prohibition Notice Localm edia	Majrpublic concern Prosecution by regulator, extensive m edia coverage. Impacton share

			Percentage Chance of Occurrence	Frequency of Occurrence
likelihood	Almost certain to occur	5	>80%	> monthly continuous reoccurrenc es
	Very likely to occur	4	50% - 80%	1 month - 1/4 year once per well
	Likely to occur	3	20% - 50%	1/4 year - 1 year
	Unlikely to occur	2	5% - 20%	1 year - 3 years more than once during
	Very unlikely to occur	1	<5%	> 3 years once during project lifetime



The MMV conceptual plan reveals important information about the feasibility of CO2 storage within the subject reservoir. The study thus far concluded that major risk scenarios that could lead to a lack of CO2 containment within the storage area exist for legacy wells and deeper transition wells. Management of these risks include workover of these wells with careful selection of well construction materials, careful placement of injection and monitoring wells, comprehensive plugging and abandonment of legacy wells and strict adherence to maximum injection pressure recommendations from geomechanical analyses.

Risk Category	Average Risk
Migration along deeper transition wells	
Migration along legacy P & A wells	
Migration along newly P & A wells	
Migration along injector wells	
Migration along monitoring wells	

Figure 22—Risk rating wells summary type

Following the detailed well integrity assessment, CO2 storage in the reservoir remains feasible and technically favorable. Candidate wells requiring remedial works were identified in a reservoir CO2 storage project. Cost estimates were generated based on the type of remedial work required. Total costs and cost schedule are provided. These costs must be taken into account in the CO2 storage project economics.

An Alternative scenario is that it is possible to delay CCS on these fields until such time as the large production well stock is nearing the window of P&A or workover. This will reduce incremental cost directly associated with remediation prior to CCS, both directly with workover costs and indirectly with revenue loss from P&A of active producers.

Integration and Economics Impact

A number of key factors were found to have major impact on project economics:

- *Injection volume*. Higher annual injection volume would be more favorable for economics, and this can be achieved by drilling of more injectors. However, the field is somewhat congested, this may limit the number and placement of wells, see also below on facilities.
- *CO2 transport pipeline, surface injection facilities*: CO2 transport pipeline and surface injection facilities represents the bulk of upfront project CAPEX. Pipeline design, construction and operating costs would vary by diameter-km, as required injection pressure at the reservoir is known to increase with time. Pipeline and surface facilities CAPEX plays a major role in project economics.
- *Project start-up timing*: Project start-up timing is quite complex. If start-up by gas production cessation and end of oil rim development, there would be considerable saving from the need of existing well workovers. However, reservoir pressure may be fairly low by then, which would make CO2 injection well design and flow assurance aspects quite challenging.
- *CO2 injection well design and operation*: An extended field test was conducted at two CO2 injectors, considerable CO2 cooling was observed. In fact, cooling was found to increase along with increase in injection rate. When CO2 injection first commences, lower reservoir pressure may mean CO2 can be in vapor phase in the tubing. In addition, J-T effects, hydrate formation potential near-well-bore or worst near-well-bore-but-within-reservoir are key design factors to be addressed. Thermal stress due to JT effects was assessed to ensure cap-rock integrity.

An iterative looping approach was adopted to maximize the project value while minimizing technical risks. Multi development scenarios were generated, for example, different CO2 arrival pressure and temperature at the field. Despite the above mentioned challenges, it was concluded that the significant estimated CO2 storage capacity and the location of the reservoir within an operating oil and gas field provides an excellent opportunity for CO2 sequestration.

Conclusions

This paper addresses significant feasibility and design challenges of CO2 storage in a giant depleted carbonate gas reservoir, and share an innovative approach to maximize project economics by addressing the different requirements and risks in an iterative looping manner. This helps to minimize over-design/ engineering while ensuring feasibility. Further optimization are planned to address some of the technical challenges identified. It is hoped that the study approach can offer discernment to operators planning similar studies.

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