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Concepts and strategies to evaluate and optimize the planning for a Carbon Capture and Storage process in stratified carbonate formations

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Abstract

ADNOC is advancing CCS as one part of the UAE's strategy to reach net zero by 2050. CCS holds large potential in the UAE, where the formations can store large amounts of CO_2 if the injection system is correctly designed. This paper presents a robust design process to ensure longevity of CO_2 injection as well as an approach to optimize well placement and well number, to ensure low unit technical costs and ensure that the process maintains the migration of the CO_2 plume to within the certified volume of interest.

To assess the short term injectivity and long-term storage of CO_2 as part of a CCS project we evaluate the potential use of two different carbonate aquifers in the emirate of Abu Dhabi. Key uncertainties have been evaluated. New wells will be drilled for the full-scale project. We evaluate how best to drill, complete and operate the wells and design procedures to monitor and enhance the overall long-term performance.

This large system comprises two thick carbonate formations. The upper zone must be operated at a lower pressure to ensure seal integrity. An intervening shale prevents flow between the two carbonate zones. Wells are designed to have CO_2 injection capability of up to around 1.5 MTPA per well and a project lifespan of many decades. Different drilling and completion strategies were evaluated with the objectives of high injectivity and minimization of overall net present cost. Options to extend the project lifespan by many more decades have been investigated. A series of observation wells may be converted to water production wells as a contingency to ensure high CO_2 capacity and injectivity and to influence plume migration. Perforation depths will have a significant standoff from the seal formations to reduce the possibility of seal integrity from perforation operations.

Introduction

ADNOC is advancing CCS as one part of the UAE's strategy to reach net zero by 2050. CCS holds large potential in the UAE, where the formations can store large amounts of CO_2 at a low Unit Technical Cost (UTC) if the injection system is correctly designed.

To assess the potential for site selection for a future CCS project, we evaluate the injectivity and long-term storage of CO_2 to a region in the UAE. The storage and seal zones are well known in the region and are extensive, underlying most (if not all) of the country. Extensive 3D seismic was available to map the subsurface horizons and faulting. Regional wells are available to estimate and set formation properties such as lithology, porosity and permeability as well as pressure and water salinity. The site has been selected in accordance with procedures found in ISO-27914. The site is characterized by two thick stacked carbonate formations which initially contain only high salinity water. The topmost seal consists of a carbonate formation in which there are many laterally extensive, thick anhydrite layers. A thick, extensive ultralow permeability shale separates the two carbonate storage formations. The base seal is a tight carbonate zone.

The development strategy is evaluated and optimized using a commercial reservoir simulator that allows advanced scripting and control.

Many key uncertainties and risks have been addressed during the feasibility assessment and development strategy design. This extended abstract will present the results of three of these key areas:

a) Method to ensure the minimum number of wells in the optimal location

b) Completion strategy to optimize monitoring and injection control

c) Sensitivity to operating pressure and mitigation methods

Method

The geologic model spans a significant part of the Emirate of Abu Dhabi (roughly 175 km x 140 km and from surface to about 11,000 foot depth as shown in Figure 1. For computational efficiency, the geologic layers are reduced to include only the seal zones and the storage formations. The main grid size is 500 m by 500 m and local grid refinement is implemented in the CCS volume of interest (VOI) to allow better resolution of pressure and fluid fronts. As much detail was included in the model as available and necessary and in all cases, the data was biased towards a pessimistic outcome. For example, we intentionally selected a permeability function that is closer to a P_{60} than a P_{50} for the midpoint: there is a 60% likelihood that the permeability will be equal to or greater than what has been used in the model.

For the process set up, around 35 potential gas injection candidates were positioned in the model and set to be “undrilled” at the beginning of the run (Figure 2). An advanced drilling queue system was used to ensure that sufficient wells were drilled to meet field injection targets. If additional injection was required, an additional well would be activated. The drilling order was examined both by the potential gas injection of each well and by a prescribed drilling order.

Figure 3 shows the completion strategies that are evaluated. Horizontal wells were not deemed possible in this formation due hole instability. The perforations will have a standoff from the top seal formation of around 100 feet to allow pressure dissipation between the open perforation and the seal rock and ensure that no perforation inadvertently is placed in the seal rock by mistake. This will ensure that the seal rock integrity is maintained. Other seal layers have a smaller but still significant standoff.

The operating pressure was set based upon the formation fracture pressure of the topmost seal. The impact of pressure control was evaluated by allowing the BHP of the top storage injection perforation to be above or below this requirement, by a variation of up to 15%.

The model was run for the required injection period of up to 50 years in some sensitivities and then for a quiescent period of at least 100 years (but was also evaluated up to 900 years).

Results and Discussion

Optimal well count and placement. The candidate wells can be activated either by the total injection potential of both zones at a given location or by defining a specific drilling order. The first pass was to allow wells to be activated by potential, and then to examine the CO_2 plume migration and how the best locations can be clustered together, then defining the drilling sequence according to this order. The plots of the active wells are shown in Figure 4. It is found that for the targeted injection requirement, around 10 wells were required for the case where the development is clustered by defining a specific order for well activation. In contrast, if the wells are activated by the injection potential, only 8 wells are required. However, this savings in drilling cost will be more than offset by an increase facility and pipeline costs.

Optimal completion strategy

Results of this work demonstrate that the ideal completion method for this system is a dual completion design for both gas injectors and pressure observation/water offtake wells to ensure monitoring and control of each zone independently. The two zones are roughly 1400 feet and 900 feet thick each, separated by a continuous shale zone of around 20 feet thick. Single zone completions, while less expensive, compromise the ability to monitor and inject at optimal rates, as the pressure in the wellbore would necessarily be limited to ensure the top seal is not fractured. This leads to under-utilization of the lower formation as a storage zone.

Operating pressure sensitivity

Given the uncertainty of the cap rock parting pressure, the model was run with a sensitivity to bottom hole injection pressure. It was found that for lower specified bottom hole injection pressure, 15 wells (an increase of 5 wells) will be drilled to meet the field injection target compared to the base case. If the process can be operated at a higher BHIP only 8 injection wells are required, a reduction of 2 wells.

Conclusions

Overall, the design is flexible and robust and has been certified by an external party. ADNOC is proceeding with more detailed studies to derisk the operating design and address additional uncertainties, many of which are being addressed by an extensive laboratory study and a field injectivity study. Results of these studies, expected mid-2025, will be incorporated into the model and the process optimized.

References

"**Carbon dioxide capture, transportation and geologic storage**", ISO-27914 Edition 1, 2017; https://www.iso.org/standard/64148.html

"**The UAE's Net Zero 2050 Strategy**", updated May 2024: https://u.ae/en/about-the-uae/strategies-initiatives-and-awards/strategies-plans-and-visions/environment-and-energy/the-uae-net-zero-2050-strategy

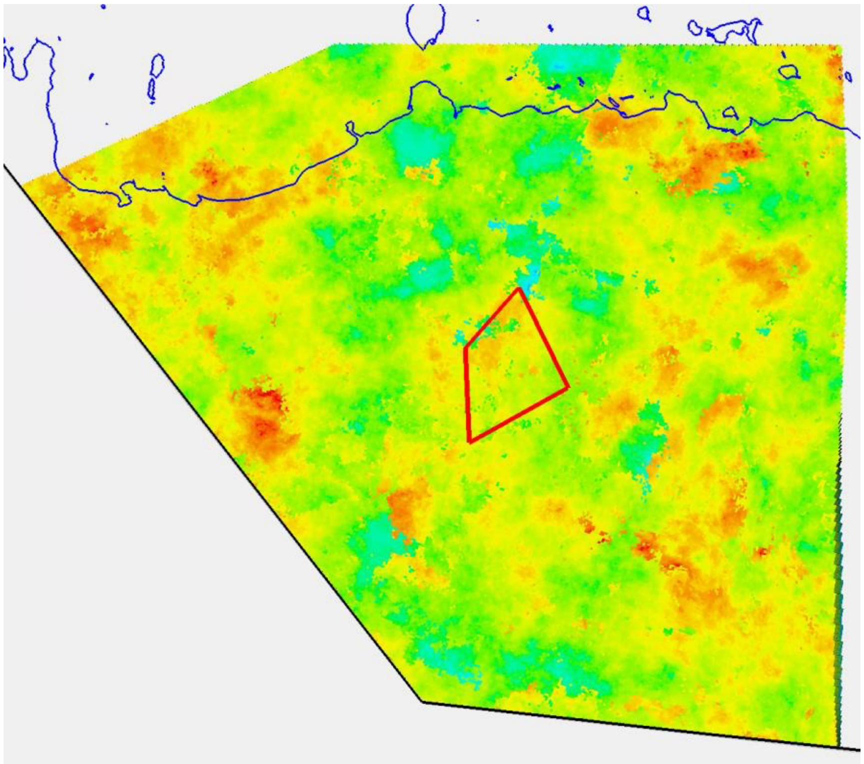

***Figure 1**: geologic model which shows the Volume of interest (VOI) for the CCS project (the red diamond). The VOI has an area of approximately 140 thousand acres.*

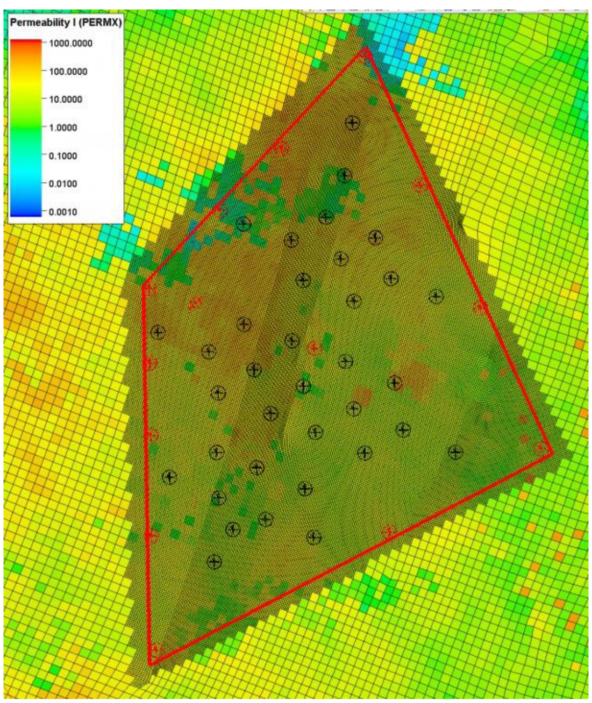

***Figure 2**: Placement of potential gas injection wells (black dots) and the observation wells (red dots) in the Volume of Interest (also shows the LGR structure).*

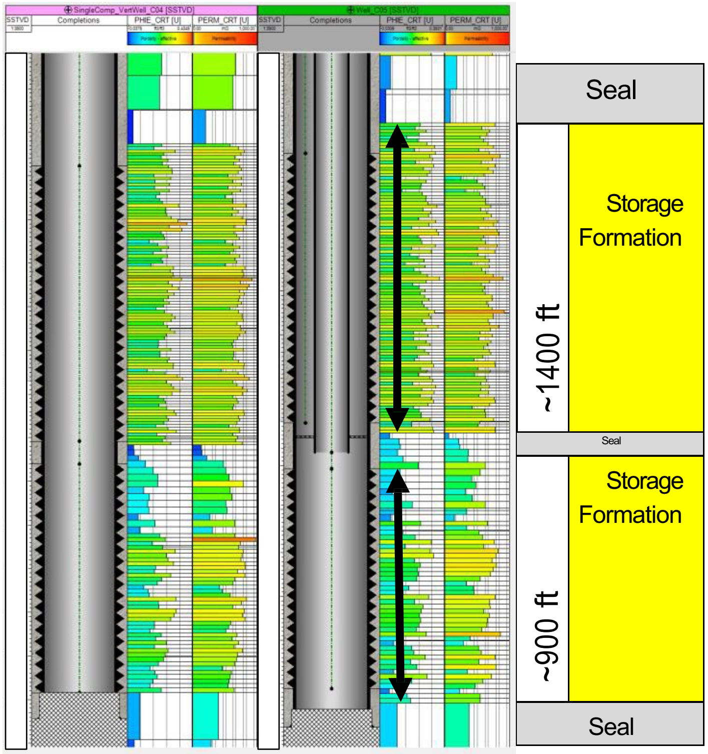

***Figure 3**: Single and Dual completion set up, also showing the sequence of sealing and storage formations.*

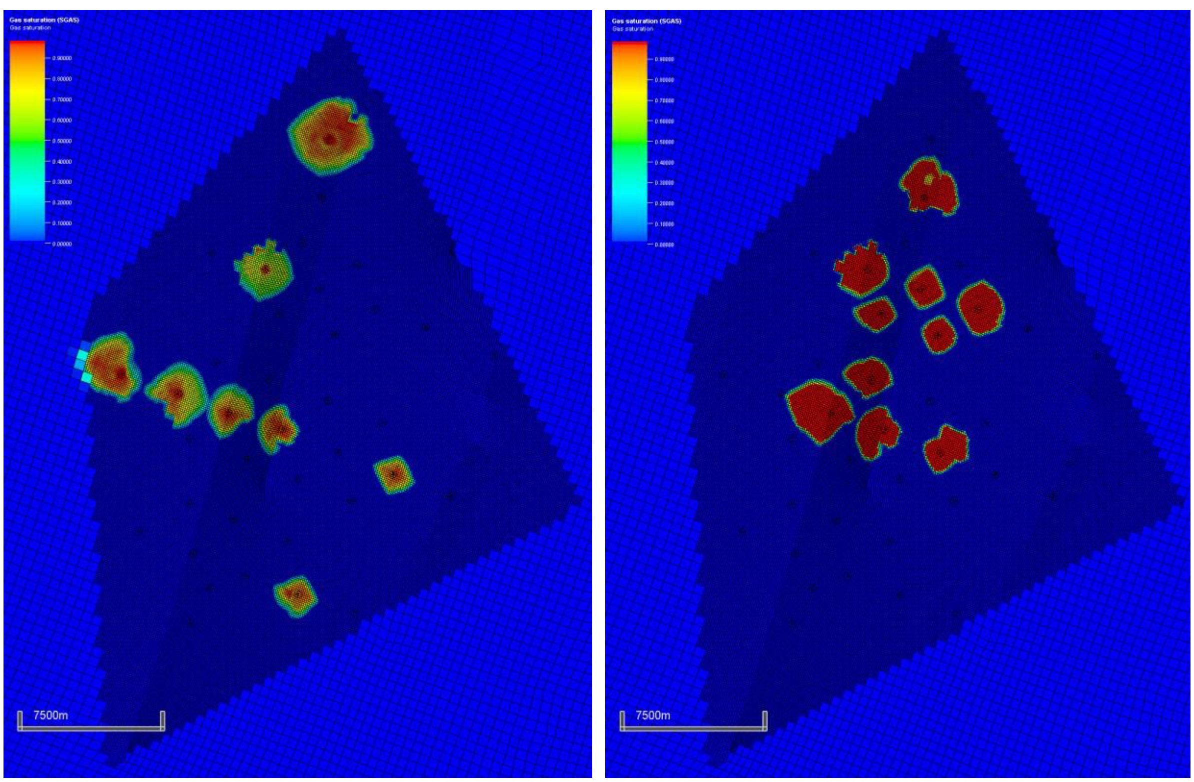

***Figure 4**: Location of wells for Drill-By-Potential (left) vs Drill-By-Order (right)*

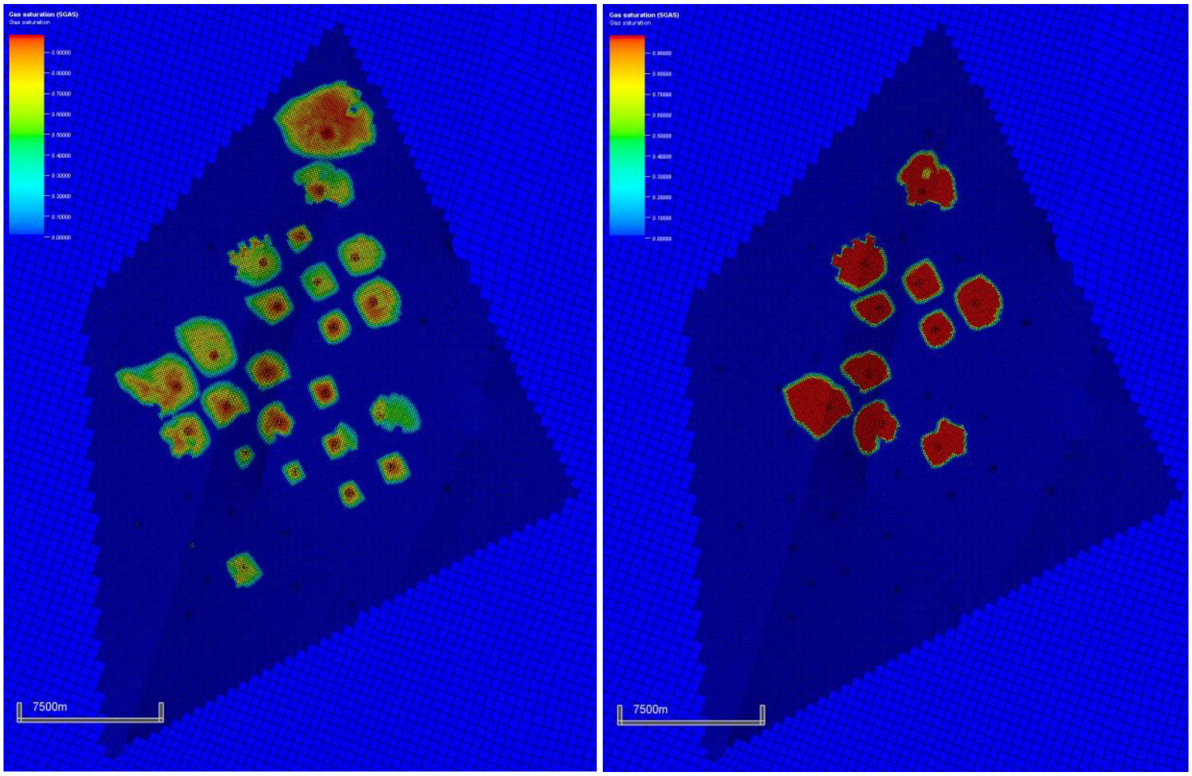

Figure 5: *Total well count for single completion (left) and dual completion (right) wells.*

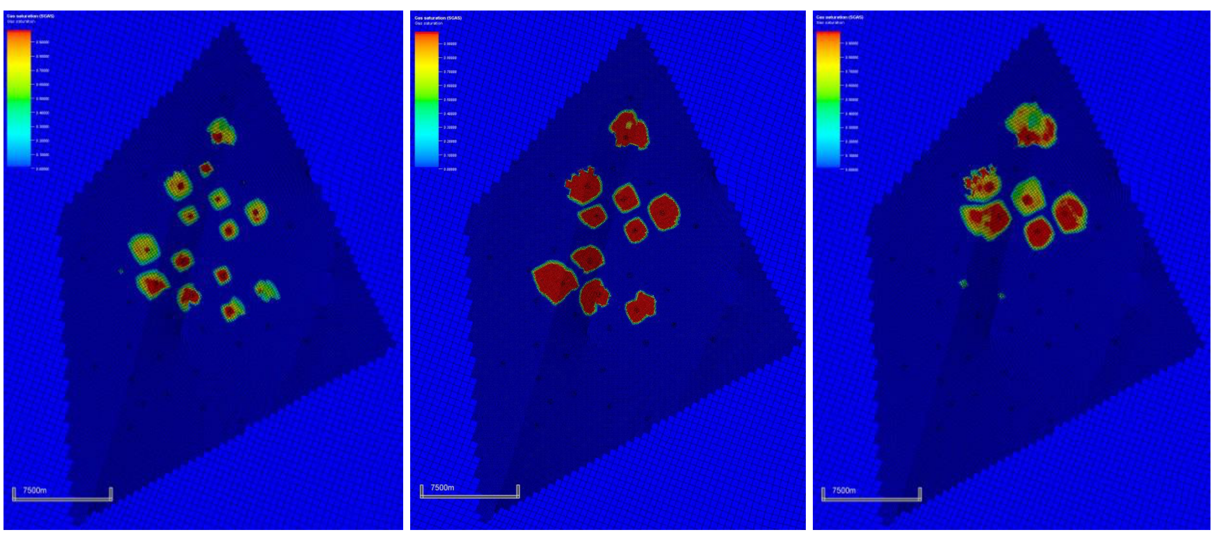

Figure 6: *Total well count and locations for operating BHIP of -15%, 0%, +15% deviation from base case.*