Introduction

Risk evaluation in Carbon Capture and Storage (CCS) operations serves as the foundation for an efficient Monitoring, Measurement, and Verification (MMV) framework, which is critical to prevent unwanted events and mitigate their consequences.

Current risk analysis approaches are inherently subjective and most of the times qualitative, as they often rely on expert judgment and interpretation. This subjectivity poses significant challenges, particularly given the long duration of CCS projects, which can span decades and involve changes in personnel, expertise, and organizational priorities over time. Variability introduced by subjective assessments can lead to inconsistencies in decision-making, undermining the robustness and effectiveness of the MMV processes.

We propose here a general framework to enable subsurface modelling-based quantitative risk assessment (QRA). By utilizing numerical metrics directly derived from the subsurface evaluation results, user dependency and bias can be minimized, enabling more standardized and reproducible assessments. This shift to Modelling, Monitoring, Measurement, and Verification (3MV) will enhance transparency and facilitate clearer communication with regulators and public stakeholders, fostering greater trust and collaboration throughout the lifecycle of CCS operations.

Numerical Model of CO2 Injection and Storage

In this study we have used the SEAM CO_2 geological model, developed as part of the SEG's SEAM CO_2 Project (Barranco et al., 2024; Yoon et al., 2024). The model is a hypothetical onshore shaly-sandstone target aquifer (420 m thick at around 1600-2000 m depth) with a caprock and two additional shallower aquifers: one situated approximately 500 m below the surface, measuring 100 m in thickness (Upper Aquifer), and another positioned around 1500 m deep with the same thickness (Mid Aquifer). There is a shaly seal layer (Caprock) at a depth of 1600 m and 95 m thick (Fig. 1).

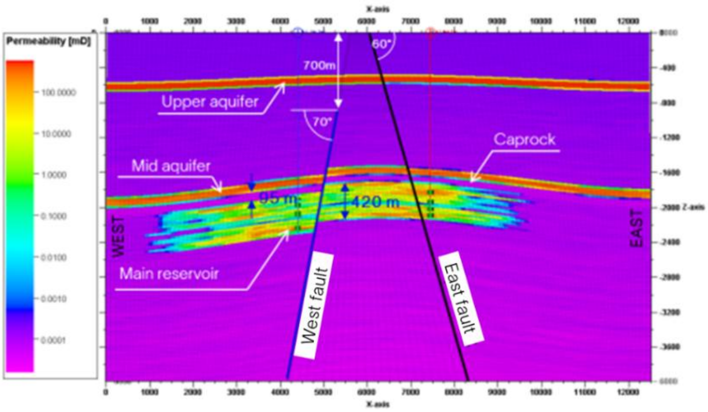

***Figure 1**. 3D model used in the study.*

The 3D model consists of 2,666,250 cells encompassing 12.5 km laterally and 4 km vertically, while the geomechanical grid is expanded to 12 km vertically to minimize the boundary effect. Two injection wells are positioned respectively on the West side of the West fault and the East side of the East fault. Injection wells have been intentionally placed near the faults to model the potential fluid migration and fault reactivation.

The permeability of the storage complex ranges from a few hundred nD in the caprock to almost 1000 mD in the main reservoir. In between the two aquifers permeability of the overburden ranges from 6 to 8E-4 mD, and above the Upper aquifer the permeability of the intact rock is assumed 1E-4 mD. Two North-South-striking faults are included in the model, separated by approximately 2 km at the reservoir zone. It has been assigned an initial horizontal permeability of 1E-4 mD and vertical permeability of 6E-5.

For the initial condition, it has been assumed that the reservoir is fully saturated with saline water with a salinity of 170,000 ppm, pore pressure gradient is 0.158 bar/m and temperature gradient is 0.025◦C/m starting from 20◦C at the surface. In all simulations, supercritical-phase CO_2 was injected into the aquifer continuously for 30 years with the rate of 1.2 MMm3/d for the West side and 2.4 MMm3/d for the East side with a bottomhole pressure (BHP) constraint of 400 bars (Yoon et al., 2024). The methodology adopted for faults is that of an "equivalent" material where the behaviour of intact rock and discontinuities is lumped considering the discontinuity fraction (a). Fault stiffness is estimated in both normal (K_n) and shear (K_s) directions considering Young's modulus of the intact rock (E) and the grid cell size (S):

$$E_{eq} = aE_{rock} \qquad K_n = \frac{1-a}{aS} E_{rock} \qquad K_s = \frac{K_n}{2}$$

Faults obey to the Mohr-Coulomb failure criterion. The remainder of the model, including the reservoir and the embedding area, was assumed to behave linear elastic. Flow and geomechanical parameters used for the base case are detailed in Table 1.

Properties	Variables	Value	Unit
Fluid	Composition [H2O/CO_2/NaCl]	[94.07/0…/5.93]	%
	Salinity	169,808 (=3.5m_NaCl)	ppm_m
Hydraulic	Fault's Porosity	0.1	Fraction
	Horizontal Fault's Permeability	1E-4	mD
	Vertical Fault's Permeability	6E-5	mD
	Temperature	20 + 0.025· Depth	ºC
Reservoir Mechanical	Density	2.05 ~2.4	g/cm^3
	Young's modulus	0.52 ~16.98	GPa
	Poisson's ratio	0.18 ~0.27	
	Biot's coefficient	1	
Fault mechanical	Cohesion	1	bar
	Tensile Strength	1	bar
	Friction Angle	35	degree
	West Fault Normal Stiffness	896.56 – 17,890.34	bar/m
	East Fault Normal Stiffness	199.26 – 17,790.46	bar/m
Injection plan	Volumetric flow rate	West = 1.2 ×10^6 (≈ 42 MMSCFD)	Sm^3/D
	Constraint	East = 2.4 ×10^6	Sm^3/D
		400 (BHP_{max})	bar

Table 1. *Reservoir and geomechanical properties assigned to the 3D Mechanical Earth Model.*

Two-way coupled simulations

In traditional O&G reservoir simulations faults permeability is considered constant during production. However, permeability of a fault depends on its tendency to open or close under the applied stresses that evolve over time as a function of the pressure change. Two-way hydro-mechanical (THM) coupling allows to account for these processes by correlating stress changes to permeability changes (Sorgi et al. 2024). Fig. 2 shows the fault permeability updating function used in this study.

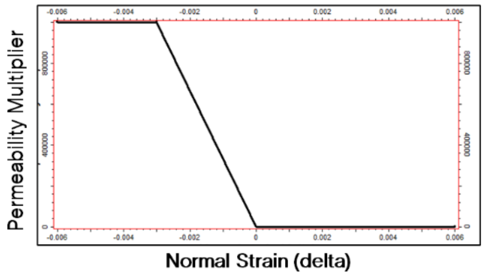

Figure 2. *Fault permeability updating function used in the two-way coupled simulations.*

Base Case, Uncertainty Analysis and Model's Ensemble Processing

With the assumptions described in the previous paragraphs two-way coupled simulation predicts a limited leakage of CO_2 in the Mid Aquifer due to the injection in the East Well and in the West Fault plane because of the injection in the West Well (base case, top left snapshot in Fig.3). A preliminary sensitivity analysis has informed on the impact of the different parameters on the simulation's outcomes.

We have identified three uncertain variables to explore the CO_2 leakage prediction; namely, friction angle, stiffness of the faults and overburden permeability. Uniform distributions have been assigned to those inputs to represent their variability. Box-Behnken design (Liu and Zhang 2011, Saeedi and Karami 2020) has been adopted as a sampling method to propagate uncertainty through the base case. Ranges of uncertainty variables are shown in Table 2. A total of 13 realizations are defined by the Box-Behnken design (Fig.3).

Parameter	Distribution (min, max)	Unit
Friction angle	Linear (22, 45)	degree
Stiffness multiplier	Linear (0.1, 10)	
k_Z OVB multiplier	Linear (1, 1,000)	

***Table 2**. Ranges of uncertainty variables assigned to represent their variability.*

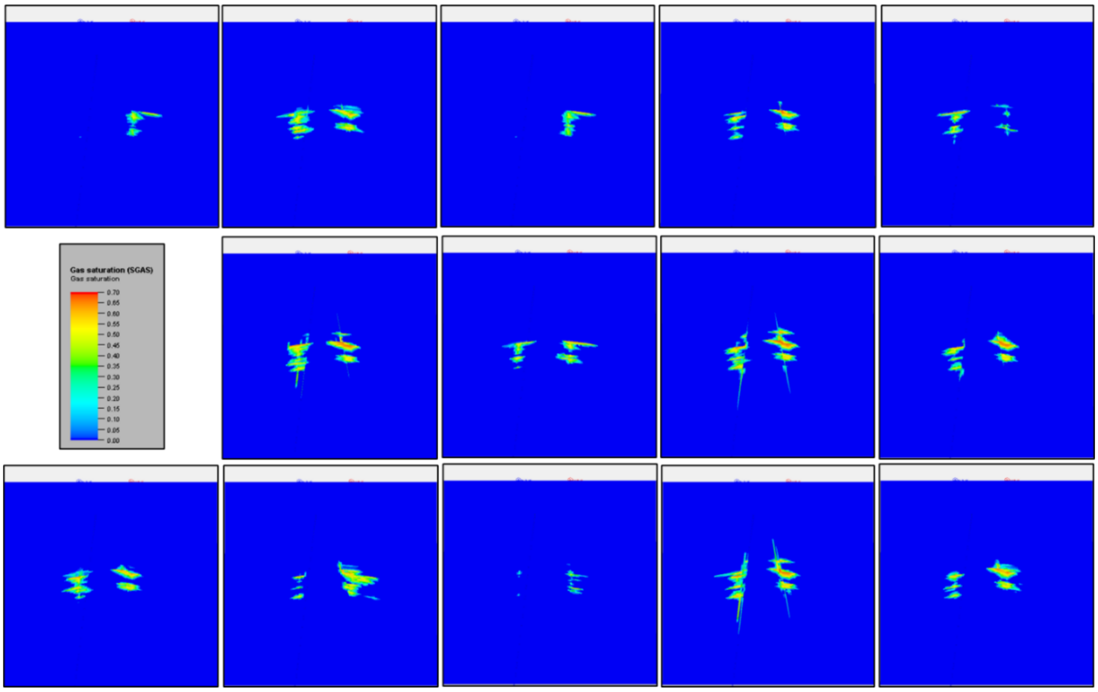

***Figure 3**. CO_2 saturation predicted through the model's ensemble resulting from the uncertainty analysis. Base case corresponds to the top left snapshot.*

Quantitative Risk Analysis

The methodology to quantify leakage probability, severity and risk relies on the post-processing of the model's ensemble results shown in Fig.3 (Sorgi et al. 2024). These realizations enable to assess the probability of a leakage event (i.e. non-zero CO2 saturation) and its severity, allowing to provide a quantitative risk scoring. Probability has been calculated in each cell of the 3D grid and for each pressure step providing a geospatial and temporal distribution of the probability of occurrence of CO2 leakage (Fig. 4 a and d). CO2 leakage severity has been addressed considering where the leakage is predicted to occur (zones criticality) and the amount (mass) of CO2 released (Fig. 4 b and e). In this analysis zone criticality increases moving from deep to shallower zones. This combined severity allows to better assess consequences of a leakage. If a reduced amount of mass of CO2 is released in a critical zone the severity will be high while if the same occurs in a non-critical zone, it will be low. Leakage probability and leakage severity at each timestep have been then multiplied to score the risk of leakage (Fig. 4 c and f). The risk of leakage matrix color code used is shown in Fig. . Results show that the risk of leakage score and extension increases over time and reaches its maximum at the end of injection. In the ten years post-injection risk leakage decreases but is not eliminated. A high risk of leakage is predicted along the West Fault that represents a pathway for CO2 to reach both aquifers. A high risk of leakage is also predicted from the injection in the East Well but limited to the mid-aquifer.

Conclusions

The numerical results of the subsurface coupled model ensemble have been used to assess probability, severity and risk of leakage in a quantitative way. These results can be used to formulate 3MV strategies for an optimized and cost-effective risk mitigation.

We have focused in this study on the QRA of leakage risks through faults, but other applications are possible, such as: leakage risks through the caprock, lateral CO_2 migration (permit limits violation), leakage risks resulting from loss of well integrity, risks associated to surface/seabed heave, risk of induced seismicity.

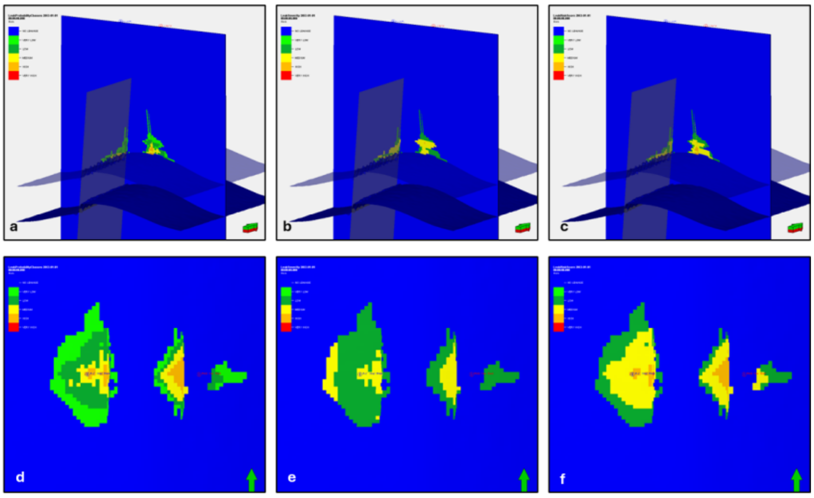

Figure 4. Quantitative Risk Analysis results at the end of injection. View on the East-West *vertical section passing through the wells: a) leakage probability; b) leakage severity; c) leakage risk score. View on the Upper Aquifer top: d) leakage probability; e) leakage severity; f) leakage risk score.*

Leakage Probability \ Overall Leakage Severity	Very low	Low	Medium	High	Very High
Very Low	Very Low 1	Very Low 2	Low 3	Low 4	Medium 5
Low	Very Low 2	Low 4	Medium 6	Medium 8	Medium 10
Medium	Low 3	Medium 6	Medium 9	Medium 12	High 15
High	Low 4	Medium 8	Medium 12	High 16	Very High 20
Very High	Medium 5	Medium 10	High 15	Very High 20	Very High 25

Fig. 5. *Risk of leakage scoring matrix.*

Acknowledgement

This work is a separate study, building and extending on the SEG's SEAM CO2 Project. The present analysis was further developed by the authors using a modified flow-geomechanics version of the SEAM models. We are grateful to SEAM and SLB for supporting this work.

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