Impact of H₂S in Predicting the Storage Efficiency of CO₂ Injection in a High Pressure High Temperature (HPHT) Carbonate Aquifer – A Case Study in a Sarawak Offshore High CO₂ Gas Field, Malaysia.

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Abstract

Carbon capture and storage (CCS) has been identified as transformative technologies to achieve maximum reductions in CO₂ emissions specified under the Kyoto Protocol. Historically, CO₂ was first stored in reservoir indirectly back in 1970s during Enhanced Oil Recovery (EOR) process. Subsequently in 1996, the Sleipner CO₂ storage project was officially implemented in Norway providing reference to future CO₂ storage projects. As one of the main players in the oil and gas industries, PETRONAS has been proactive in finding an end-to-end technology development for CCS. It has recently identified the S field, a non-associated gas field, located 250km Offshore Sarawak Malaysia as a potential pilot hydrocarbon production and CO₂ storage gas field - one of the strategic technology pilot project to mature both surface and subsurface technologies. The S field, a carbonate build up platform is considered heterogeneous type of reservoir with porosity ranging from 15% to 40% and permeability ranging from 10md to 1300md. The S field contains 70% CO₂ gas contents with some amount of impurities, N₂, H₂S and Hg. As a baseline development strategy to support this technology project, pure CO₂ injection was considered, taking into account the separation technology efficiency to separate CO₂ from other contaminants gas back into the same reservoir aquifer. However, due to some limitation on the surface technologies, traces of impurities might be present in the system. There is a possibility of CO₂ being co-injected with other impurities, such as H₂S. The presence of H₂S in the injected CO₂ stream need to be evaluated and quantified to ensure the storage plan is not affected. Changes in base CO₂ solubility may ultimately affect storage integrity and capacity. Understanding the impact of H₂S impurity on CO₂ solubility in brine is one of the key parameters to ensure successful any CO₂ sequestration project. To understand this effect, an extensive laboratory experiments on CO₂ solubility has been conducted to quantify the impact of H₂S (up to 5% level of H₂S concentration) to the system. Generation of accurate experimental data for CO₂-H₂S-H₂O ternary system for the above parameter are made available, covered a satisfactory ranges of
impurities level at desire field pressure and temperature, up to 400 bar and 150°C respectively. CO2-H2S mixture is introduced into the cell directly from the gas cylinder (or the auxiliary cylinder holding the binary mixture) to pressurize the equilibrium cell to start off the measurements. A series of CO2 injection with different pressures, up to reservoir pressure are injected after each of the vapour and liquid sampling for solubility measurement. Following this, thermodynamic modelling has been carried out utilizing all the experimental data in making sure the good agreement between experimental data and modelling/literature are obtained. The best Equation of State (EoS) model with the least Average Absolute Deviation percentage (AAD) was chosen to represent the system prior to the reservoir dynamic simulation study. Two different reservoir simulation injection scenarios were evaluated, to characterize the system with and without the presence of H2S. Fifteen years of CO2 injection below the gas-water contact with a single injection rate was defined for both cases. However, both cases were simulated without considering the geo-mechanical and geo-chemical effects. Simulation results were then analysed based on the plume migration, volume of CO2 mobile in free phase, volume of CO2 trapped as immobile, volume of CO2 dissolved in water and total volume of CO2 gas injected. The comparison between the cases indicate insignificant impact if 5% of H2S is co-injected with CO2 gas, hence answered the earlier research problem statements. Sensitivity studies are currently being conducted to evaluate the allowable ranges of H2S that can be co-injected with CO2 in reservoir aquifer without affecting the CSS objective. Further details of the laboratory study, fluid modelling and simulation results will be shared in the full paper.