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# Prediction of Increment in Recovery through $CO_2$ Injection Using CMG

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**Abstract.** The following research provides a comprehensive forecast regarding the incremental recovery of oil through the application of carbon dioxide injection within a mature hydrocarbon reservoir. This study utilizes compositional reservoir simulation via the Generalized Equation-of-State Model (GEM) to analyze various recovery scenarios. By maintaining a consistent grid and rock framework, a history-matched base case was compared against multiple injection strategies, including continuous gas flooding, water-alternating-gas cycles, and operations with varying injection pressures. To ensure the simulation accurately reflected subsurface phase behavior and miscibility limits, the model underwent rigorous equation of state tuning and minimum miscibility pressure estimation. Further analysis through sensitivity and Monte-Carlo methods helped quantify uncertainties related to reservoir heterogeneity, permeability, and relative permeability endpoints. The findings suggest that miscible injection at pressures significantly higher than the minimum miscibility limit provides the most substantial recovery gains. Additionally, mobility control strategies such as water-alternating-gas schemes were shown to enhance volumetric sweep efficiency in complex, heterogeneous systems. Findings indicate that miscible $CO_2$ injection (injection pressure 3 MMP and above) gives the highest incremental recovery, whereas WAG schemes enhance volumetric sweep and efficiency in the use of $CO_2$ in heterogeneous systems. Key operational drivers of incremental recovery were injection pressure relative to MMP, mobility control (WAG or foam/chemical agents), and $CO_2$ recycling rates. The study emphasizes risk associated with asphaltene precipitation and impurity effects on MMP, suggests monitoring parameters ($CO_2$ breakthrough, produced $CO_2$ recycle fraction, and saturation maps), and how the economic sensitivity of incremental barrels to $CO_2$ cost and project NPV is established.

**Keywords:** $CO_2$ injection, Enhanced Oil Recovery (EOR), CMG-GEM, Compositional simulation, Minimum Miscibility Pressure (MMP), Water-Alternating-Gas (WAG).

## I. Introduction

$CO_2$ injection works through two dominant displacement mechanisms: miscible flooding and immiscible flooding. When it is under miscible conditions, $CO_2$ dissolves in the

reservoir oil that reduces its viscosity and interfacial tension between phases that improve microscopic displacement. When the $CO_2$ is immiscible, recovery performance is reduced because of the swelling of oil and increase in reservoir pressure with respect to miscible $CO_2$. The $CO_2$-EOR development is critically dependent on the attainment of Minimum Miscibility Pressure (MMP) as well as circumventing. Predicting the incremental recovery due to $CO_2$ injection requires a comprehensive understanding Sustained decline in legacy oil production and increasing worldwide energy demands has increased the requirements for enhanced recovery methods, which can recover more hydrocarbon from matured or declining reservoirs.

Primary and secondary recovery techniques, including natural reservoir drive mechanisms and water flooding, often recover only 30–40% of original oil in place (OOIP). Residual hydrocarbons are frequently held because of mobility contrasts, capillary effects and reservoir heterogeneities. To overcome this problem, EOR has been developed to mobilize and recover the left oil, which includes thermal, chemical and gas flooding methods of those technologies, Carbon Dioxide ($CO_2$) flooding is becoming one of the most effective and frequently performed EOR processes at which Enhanced Oil Recovery (EOR) can also be combined with Carbon Sequestration.Cg the gas/water mobility ratio between injected gas and displaced oil. Additionally, Water Alternating Gas (WAG) injection is used to enhance volumetric sweep efficiency and minimize gas channeling, achieving a compromise between oil production and $CO_2$ utilization.

Reservoir simulation has progressed so abundantly and became the standard for design and optimization of $CO_2$ injection projects. One of the tools available for this purpose is the software suite developed by Computer Modelling Group (CMG), especially GEM (Generalized Equation-of-State Model) simulator, which offers a solid compositional system for consistent description of CO2 oil–water contacts and phase behaviour, and fluid flow in complex reservoir systems. CMG-GEM allows for detailed modeling of PVT behavior of EOS-tuned $CO_2$ injection, phase equilibria and compositional changes that occur during injection into a reservoir.

Moreover, the investigations of the efficiency of the oil displacement and the overall success of the project under consideration are necessary to define the possibility of the $CO_2$-EOR implementation on the field scale. In addition, the efficiency of $CO_2$ utilization and the economic feasibility should be considered to define the possibility of the oil displacement efficiency. Given that $CO_2$ injection has huge costs in terms of gas purchase, compression and recycling, it is essential to compromise on injection schemes to ensure maximum recovery is possible with each unit of $CO_2$ injection. Besides augmenting oil output, $CO_2$ injection is consistent with the global initiative of carbon capture, utilization, and storage (CCUS).

The process aids in reduction of the Greenhouse gas emissions by trapping the injected $CO_2$ in the geological formations hence rendering the $CO_2$ EOR an ecologically friendly practice. This two-fold property of the $CO_2$ injection has boosted the oil recovery and reduction of carbon, therefore, making the $CO_2$ injection a major target in petroleum and environmental industry. This paper is dedicated to the prediction of incremental oil recovery due to $CO_2$ injection based on CMG-GEM compositional simulation. This

study intends to test the various injection methods, miscibility effects, uncertainty concept using Monte Carlo and sensitivity analysis and the cost-effectiveness of $CO_2$ EOR. The results of this research should have a positive contribution to the optimization of the $CO_2$ injection processes, the enhancement of the recovery processes, and the contribution to the strategy of the sustainable reservoir management and carbon usage. of the behavior of the reservoir under various operating conditions.

The researchers have developed history-matched base case model (without $CO_2$ injection) and their findings are compared to the $CO_2$ injection cases in continuous in $CO_2$ flooding, WAG cycles, and pressure-varied operations in order to be able to quantify the increase in the oil production. Also, having performed sensitivity and uncertainty analyses on the Monte Carlo simulation, the researchers brought light to the determining parameters such as MMP, relative permeability, heterogeneity, and the effect of the injection rate on the recovery performance. The analyses are used to identify the most relevant aspects that govern the oil displacement efficiency and therefore, the project success in entirety. Furthermore, the evaluation of the efficiency of the $CO_2$ utilization and economic feasibility are also a precondition of determining the feasibility of the $CO_2$-EOR method at the field scale because the $CO_2$ injection process involves high costs due to purchasing the gas, compressing it, and recycles. The combination of economic evaluation and technical predictions provides a comprehensive understanding of the recovery potential and the financial feasibility of $CO_2$-EOR projects.

## II. Literature Review

. Liuetal.,2024: An optimization methodology has been developed that integrates $CO_2$ flooding with geological sequestration and is based on CMG-GEM. Optimization algorithms were applied to the injection schedules, and it was found that the joint optimization of injection rates and sequestration objectives has a significant effect on the recommended $CO_2$ rates and WAG schedules. They pointed out that it is essential to consider $CO_2$ storage as a constraint in the estimation of incremental oil recovery.

. Su et al., 2024: Investigated $CO_2$–formation oil systems through lab experiments and simulations. The study showed that experimental setup and interpretation can significantly affect measured MMP, and variability in MMP is a major source of uncertainty in predicting miscible incremental recovery. Careful calibration of MMP in compositional simulations is necessary.

. Andreeva et al., 2024: Conducted a Monte-Carlo study using compositional reservoir modeling to quantify $CO_2$ flood efficiency across light to heavy oils. Results indicated that incremental recovery distributions (P10/P50/P90) strongly depend on oil density and injection dimensionless rate. Monte-Carlo simulations effectively quantify uncertainty in incremental recovery predictions.
. Song et al.,2024, Provided a comprehensive review of methods to determine and reduce MMP, comparing slim-tube and core flood approaches. They concluded that differences in MMP measurement and interpretation can cause large variations in predicted incremental recovery, highlighting the need to include simulation-based MMP validation in forecasting workflows.

. Parsaei et al., 2020: Investigated asphaltene precipitation through $CO_2$ injection and its prevention using nanoparticles. The researchers discovered that $CO_2$ interaction might cause asphaltene to be deposited, which in turn modifies the permeability, thus, the injectivity is reduced and they recommended that the incorporation of asphaltene models.

**Objectives**

This Study is to make predictions of the volume of oil to be expected as added oil recovery due to $CO_2$ gas injected into a mature oil reservoir through the use of a compositional reservoir model from the Computer Modelling Group GEM(CMG-GEM) simulator.

- Evaluating the simulation methods used to model $CO_2$ injection into oil and condensate reservoirs.
- To Predict the percentage increment in recovery through $CO_2$ injection using CO2 Hysteresis

**Problem Statement**

The latest research on $CO_2$-enhanced oil recovery (EOR) has confirmed that a lot of things have to be done right in terms of optimization, measurements, and uncertainty. Liu et al. (2024) showed that predicting recovery is significantly better if $CO_2$ injection schedules are optimized simultaneously with sequestration goals—and one can't really overlook storage limits. On the technical level, Su et al. (2024) and Song et al. (2024) highlighted that a Minimum Miscibility Pressure (MMP) reading fluctuates significantly in relation to the way one conducts the experiment and investigates the findings. Calibration is important if you would like to rely on simulations. Andreeva et al. (2024) demonstrated that the properties of oil, as well as the rate at which you
inject $CO_2$, are important to recovery, and that Monte Carlo compositional modeling is a sound approach to narrowing the uncertainty around the extra oil you are going to recover. Another aspect Parsaei et al. (2020) observed is that permeability and injectivity may be a blow to receive when asphaltenes start to drop out during $CO_2$ injection. So, it's smart to include asphaltene modeling in your simulations to keep recovery estimates realistic.

**Overall, the literature underscores:**

- The critical role of optimization in injection and storage strategies.
- The sensitivity of recovery predictions to MMP measurement and calibration.
- The need for probabilistic modeling to account for uncertainty.

## III. Methodology

Prediction of Incremental Recovery through $CO_2$ Injection using CMG (GEM), full, step-by-step methodology we follow selection of the simulator and the unit used in CMG

Creating the cartesian Grid and filling those grid with the properties like porosity , permeability , compressibility

Export the components from the WINPROP and creating the Rock fluid type

Doing the Initialization setting and the numerical with the time step control.

Adding the range of dates and the injector wells and running the simulation for 200 years

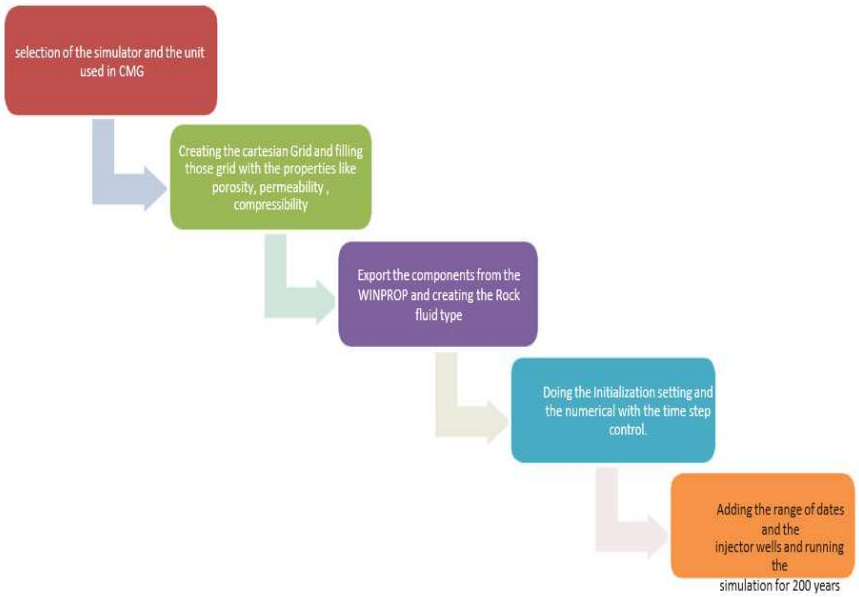


Figure 1. The Systematic workflow for predicting increment in oil recovery.

**Overview & Workflow Summary**

The methodology for predicting incremental oil recovery through $CO_2$ injection using CMG (GEM) involves To predict how much extra oil you can get by injecting $CO_2$, you need a clear, step-by-step game plan with CMG (GEM). To begin with, you first collect as much as you can of well logs from the reservoir, core samples, PVT data, production records, etc. After you have done that, you will then clean up the data, check its quality, and upscale it to come up with realistic numbers for porosity, permeability, and saturation. The properties mentioned are the basis of your reservoir model. Then, quite the opposite, a dynamic model is to be created. Here, you will position the geological and petrophysical details your grid laid out, your layers chosen, and your facies mapped. You will want to have detail that is sufficient, particularly in areas of great concern to you. That way, your simulation actually reflects what's going on underground.

Each grid block is assigned the properties like porosity, permeability and saturation functions. The model describes the heterogeneity of the reservoir and formulates the conditions at the boundaries. The grid block also receives respective properties porosity, permeability, saturation functions. This is what makes the model capture the distinctive characteristics of the reservoir and establishes the appropriate boundary conditions. To characterize fluids and tune PVT / EOS, the objective is to construct a compositional model that is in fact a reflection of the behavior of the reservoir fluids at varying pressure and temperature. In this case, lab PVT data would be useful. The Peng Robinson EOS is usually adjusted in CMG-GEM to the real measurements, such as saturation pressures and densities and viscosities. This tuning step? It is what ensures that the fluid model does not implode once it is time to simulate the $CO_2$ injection and the phase changes.

The second one is the MMP the pressure in which the $CO_2$ becomes completely miscible with the reservoir oil. It is then that you have the optimum displacement. Individuals determine the MMP using simulation and laboratory tests to ensure that the findings are sound. It is an important figure to calculate how to operate the injection process. Lastly, in dynamic model preparation, the tuned compositional model is loaded to CMG- GEM. In go wells, completion periods and boundaries as well as production and injection controls are based on actual field data. This dynamic model then emulates the dynamics of the movement of fluids, movement of $CO_2$ and the production shape up under varying operating strategies.

The dynamic model demonstrates the dynamics of the flow of fluids, the $CO_2$ flow within the reservoir, and the reaction of production to various operating policies. The first is history matching in the sense of starting with the basic model (i.e. with no $CO_2$ injection) and matching this to what has occurred in the field. You consider production rates, water cuts, pressures in the reservoir, all that, and modify factors such as permeability multipliers, relative permeability endpoints, or aquifer strength to bring the simulation as near to reality as you can make it. When the base case is online, then you have a good starting position to test the behaviour of injecting $CO_2$. Then you establish a series of various $CO_2$ injection conditions continuous $CO_2$ flooding, Water-Alternating-Gas (WAG), and conditions whereby you vary the injection pressure (below or at or above MMP).

You operate all these on the same geological and grid basis, to be able to realize the actual amount of additional oil that you get simply due to the $CO_2$. In any case, what you consider is the effect of injection pressure, WAG ratio, and $CO_2$ purity on recovering a certain amount of oil and the utilization efficiency of $CO_2$. That is followed by delving into sensitivity analysis. You can see the extent to which uncertain items such as MMP, endpoints of permeability, relative permeability, or WAG ratio have any impact on the outcomes.

You support this with a Design of During postprocessing, simulation results are used to calculate incremental recovery factors using $CO_2$ injection cases compared to the base case. The profiles of $CO_2$ mole fraction, pressure distributions and saturation are

studied to determine the breakthrough behavior and sweep efficiency. The ratio of $CO_2$ used, recovery per tonne of $CO_2$ injected and fraction of recyclable $CO_2$ produced are all performance measures that determine how well each scenario works technically. An economic analysis is then carried out to calculate the economic feasibility of $CO_2$ injection projects.

The incremental revenues of the extra oil production are measured against the expenses on the purchase of $CO_2$, compression, transportation, and recycling. Sensitivity of oil price, $CO_2$ cost, and injection efficiency are conducted to determine the project risk and profitability. Lastly, reporting, validation and monitoring recommendations are the final aspects of methodology. The results of the simulations are judged by available field or pilot data, and recommendations are given to future $CO_2$ injection monitoring including $CO_2$ breakthrough monitoring, pressure monitoring, and saturation mapping. It is a rigorous predictive approach that will guarantee a sound incremental recovery due to $CO_2$ injection with CMG-GEM that considers the uncertainties in geology, fluids and operations to create a complete simulation-based decision model.

**Data collection & preprocessing:**

You back up this one with a Design of During postprocessing which compares the conditions of the incremental factors of recoveries by comparing the $CO_2$ injection conditions with the base case using simulation results to compute them. The goal of the step is to tabulate and package credible input information to obtain steady-state and dynamic model of reservoirs to forecast incremental recovery through injection of $CO_2$ into the reservoir. This begins with collection of detailed datasets, including well logs (gamma ray, density, neutron, resistivity, and sonic) and core measurements (porosity, permeability, relative permeability), and description of core. The production history data that consists of the monthly rates of oil, gas and water production, the bottomhole pressures (BHP), the surface pressures and the history of injection is used to construct the history of the past performance of the reservoir.

The compositional studies of oil and gas, the separator tests, the constant-volume expansion (CVE) records, flash tests and measurements of viscosity changes with pressure and temperature are summed up in PVT laboratory records to determine the correct behaviors of oils and gases. To obtain significant phase and flow phenomena, specialized experimental evidence of the kind slim tube as well as core flood (to quantify Minimum Miscibility Pressure, MMP, and relative permeability and asphaltene precipitation (where possible) tests are encompassed. Reservoir engineering data such as structural maps, formation thickness faults, aquifer characterization other data such as, operational and economic parameters such as $CO_2$ supply rate Before establishment of the model, all the raw data are processed to generate quality and uniformity. Well logs are cleaned up, depth matched and interpreted to determine porosity based on density and neutron logs.

It is the equation of Archie that is used to find the saturation of water. Methods of flow that preserve reservoir differences and flow qualities are used to bring the data of core permeability up to effective grid permeability. The construction of compositional fluid tables is done using lab tests to define the molar fractions of each component in the simulation framework. Finally, it is possible to mention uncertainties and parameter

range, which can be explained by the fact that porosity variations, multiplier of permeability, relative permeability endpoint, and oil originally in place (OOIP) is reported, to conduct the following sensitivity analysis and Monte Carlo analysis with a concrete and realist simulation.

**Static model construction:**
The grid in the reservoir model was designed along with the geological formations and heterogeneity of the formation. Based on the complexity of the structure, we either drew a corner-point grid on the shape of the reservoir or a Cartesian grid, depending on the complexity of the structure. We fine-tuned the grid and closed it around the production and injection wells and at the points of where we guessed that the $CO_2$ would flow through, so we could monitor exactly how easily the saturation and composition varied. Typically, we selected a grid in the area surrounding the wells that had not less than 10 to 20 cells in the drainage radius. In that manner we got all the swings in the pressure and saturation. We divided the model vertically into layers to be able to pick up phenomena such as gravity segregation and other rock types. We always left at least three or five layers even in those slim shales or layers, lest we should leave out anything of importance. Upscaling was employed when we changed the more detailed geological model to the coarser simulation grid.

Here the primary concern was to maintain the flow pathways and transmissibility in the correct state and hence we employed a flow-based upscaling technique. In that manner, the tensors of permeability and the way the fluid was moving in various directions remained true to the initial data. In defining the important types of rock and the facies we had sand, shale, and those thief zones of high permeability. They each had their usual values of porosity and permeability, which we obtained by drawing on core samples and well logs. We also implemented relative permeability functions and capillary pressure functions which were specific to each facies. We modelled each facies or stratigraphic layer, ensuring that it was in fact realistic in the way fluids flow in the underground.

We added in hysteresis effects where possible to get fluids behaviour in $CO_2$ injection and water- alternating-gas (WAG) cycles, in other words, we wanted to do both imbibition and drainage correctly. In the case of the boundaries, we checked what the field data informed us. There is no flow in the aquifer at times, and at other times the aquifer pushes back so we configure all the way between no-flow to strong aquifer support, using Fetkovich or volumetric models to model the pressure support and peripheral drive. We equated the outermost pressures to those at the regional level and, therefore, the model would respond to the lateral pressure variation in a manner that makes sense.

To begin with, we used real field pressure and saturation data. The first pressure was established by depth, according to the pressure gradient of the reservoir. We then spread water, oil and gas saturations depending upon locality of fluid contact and capillary transition zone. Lastly, we specified the composition of the fluids in each phase based on PVT information, such that the model would remain consistent.

**Fluid characterization & EOS Tuning:**

The choice of components included in the compositional model was made in a way that brings out the most important phase behaviour of the $CO_2$ hydrocarbon system. $CO_2$ was explicitly added as an ingredient, we took some time to choose the correct components to the compositional model, and we really wanted to get a grip of how $CO_2$ and hydrocarbons interact. $CO_2$ is given a spot of its own, and we take enough pseudo-components to describe the vaporization or condensation of the hydrocarbons in the reservoir when we inject gas. Usually, we model the lighter stuff methane ($C_1$) up to hexane ($C_6$) one by one.

Then, for anything heavier, we just group it all together as one chunk ($C_7^+$) or sometimes as an even bigger lump ($C_7$–$C_{10}^+$), depending on what the PVT data tells us. If the injected gas isn't pure say, it's got nitrogen ($N_2$), more methane ($CH_4$), or hydrogen sulfide ($H_2S$) mixed in we add those to the list too. That way, the model matches what's really going into the reservoir and how it'll affect phase changes and miscibility. For the equation of state (EOS), we usually go with either Peng-Robinson (PR) or Soave-Redlich-Kwong (SRK) inside the CMG-GEM simulator. We tune these equations using actual lab PVT data things like constant-volume expansion (CVE), separator flash results, viscosity versus pressure, and $CO_2$- oil swelling tests.

The binary interaction coefficients (BICs) and the heavy-end parameters have been tweaked to bring the EOS into agreement with reality. Until the predicted and measured Minimum Miscibility Pressures (MMPs) were matched satisfactorily, the phase densities, and volumetric behavior at a variety of pressures and temperature were matched to reality. When compositional reservoir simulation is involved, the quality of recovery prediction is strongly fixed on the quality of representation of the reservoir fluid and the injected gas. The $CO_2$ injection procedure is also characterized by various types of interactions where mass transfer, oil swelling, and multi-phase behavior are minimal; therefore, the use of detailed and realistic fluid characterization method in the present study was reasonable.

The compositional model of the reservoir fluid system was built using the application of the definition of individual components and pseudo-components. The carbon dioxide ($CO_2$) was treated as a distinct entity to put its oil solubility and influence on changing fluid characteristics into consideration. The hydrocarbons were separated based on their molecular weight and the relevance of the phase behavior. The light hydrocarbons (C 1 -C 6) were handled separately to developed the vaporization effects and the composition changes in the gas phase during the process of displacement closely. The heavier hydrocarbons which are mainly in the liquid phase and known to control the oil density and viscosity, instead, were combined into one or more pseudo-components like $C_7^+$ or extended heavy-end fractions depending on the detail of laboratory PVT reports available. When the injected gas contained impurities or extra constituents, such as nitrogen ($N_2$), methane ($CH_4$), or hydrogen sulfide ($H_2S$), these components were included in the model explicitly. The reason for this inclusion is to make sure that the deviations from the ideal $CO_2$ injection conditions are correctly considered and the non- condensable or reactive gases' influence on miscibility development and phase equilibrium is simulated in a realistic manner. This procedure of defining components in detail enhances the

accuracy of predictions related to the minimum miscibility pressure (MMP) and displacement efficiency. The accuracy of compositional reservoir simulations in $CO_2$-enhanced oil recovery depends largely on a realistic representation of both the reservoir fluids and the injected gas. $CO_2$ interacts with crude oil in multiple ways—it dissolves in oil, reduces viscosity, increases oil volume, and alters phase behavior. These effects influence flow, miscibility, and ultimate recovery, making detailed fluid characterization essential. Beyond standard phase behavior, properties such as compressibility, density variations, and oil swelling must also be captured to produce reliable forecasts.

In this study, the reservoir fluid was represented using a combination of individual components and pseudo-components tailored to their impact on phase behavior and recovery efficiency.

## IV. Experimentation

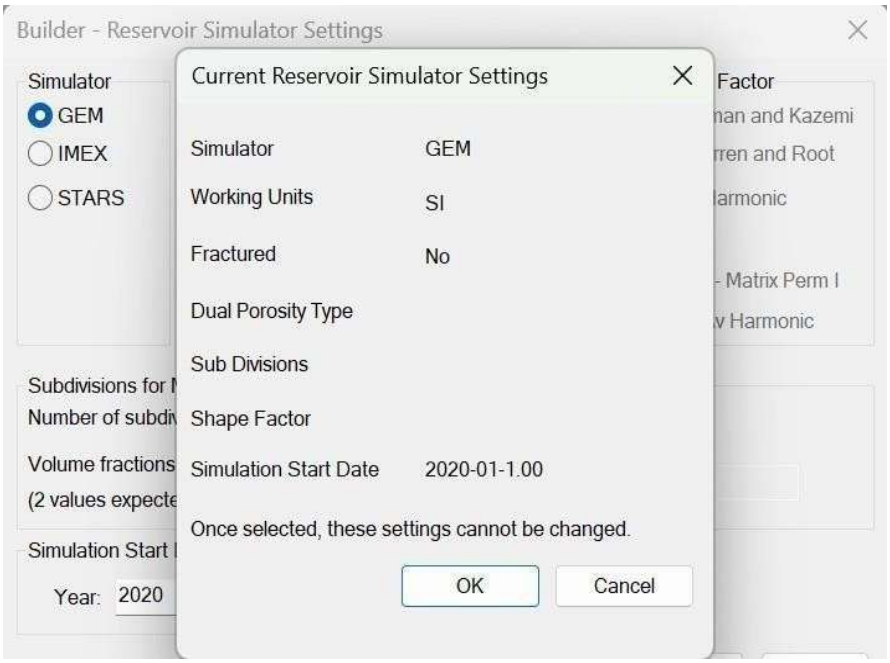


Figure 2. Selection of the Simulator and working units.

For doing this project we chose Gem simulator out of the three simulators that is IMEX, STARS, GEM. Selection of the gem simulator and the working units to be chosen as SI units where single porosity is taken, and the simulation starts date is decided.

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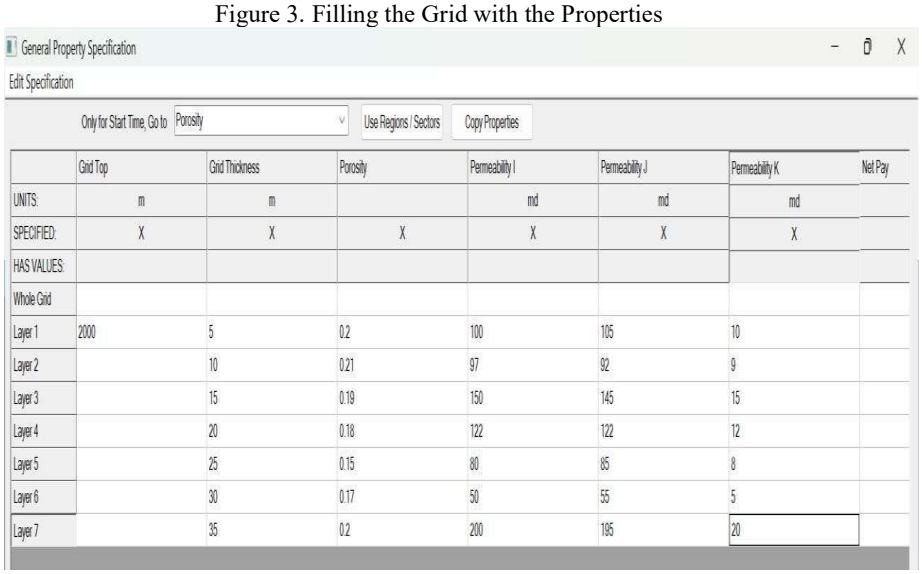
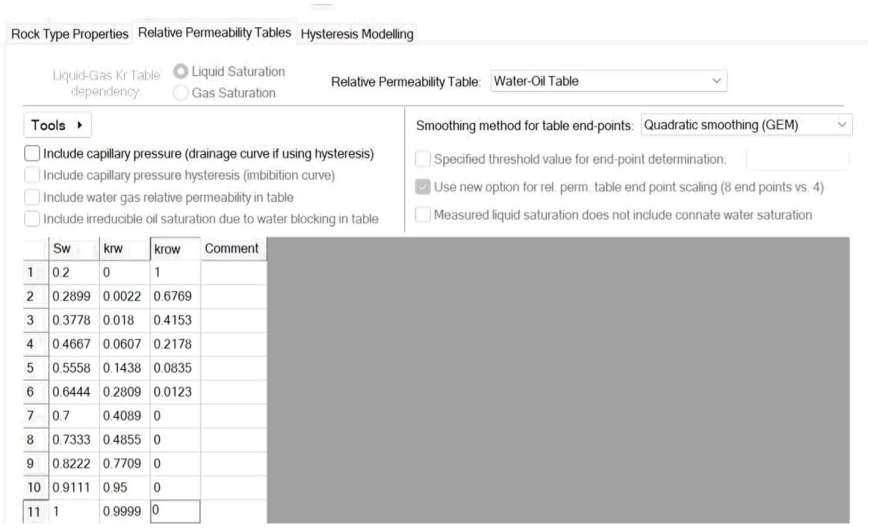
Figure 3. Filling the Grid with the Properties




| | Grid Top | Grid Thickness | Porosity | Permeability I | Permeability J | Permeability K | Net Pay |
|---|---|---|---|---|---|---|---|
| UNITS: | m | m | | md | md | md | |
| SPECIFIED: | X | X | X | X | X | X | |
| HAS VALUES: | | | | | | | |
| Whole Grid | | | | | | | |
| Layer 1 | 2000 | 5 | 0.2 | 100 | 105 | 10 | |
| Layer 2 | | 10 | 0.21 | 97 | 92 | 9 | |
| Layer 3 | | 15 | 0.19 | 150 | 145 | 15 | |
| Layer 4 | | 20 | 0.18 | 122 | 122 | 12 | |
| Layer 5 | | 25 | 0.15 | 80 | 85 | 8 | |
| Layer 6 | | 30 | 0.17 | 50 | 55 | 5 | |
| Layer 7 | | 35 | 0.2 | 200 | 195 | 20 | |

Filled the grid with the Properties like the porosity, permeability in I, J, K directions and Rock compressibility, and the reservoir is taken to be heterogeneous.




| | Sw | krw | krow | Comment |
|---|---|---|---|---|
| 1 | 0.2 | 0 | 1 | |
| 2 | 0.2899 | 0.0022 | 0.6769 | |
| 3 | 0.3778 | 0.018 | 0.4153 | |
| 4 | 0.4667 | 0.0607 | 0.2178 | |
| 5 | 0.5558 | 0.1438 | 0.0835 | |
| 6 | 0.6444 | 0.2809 | 0.0123 | |
| 7 | 0.7 | 0.4089 | 0 | |
| 8 | 0.7333 | 0.4855 | 0 | |
| 9 | 0.8222 | 0.7709 | 0 | |
| 10 | 0.9111 | 0.95 | 0 | |
| 11 | 1 | 0.9999 | 0 | |

Figure 4. Mentioning the values for saturation and relative Permeability.

The value for the saturation and relative permeability for the water-oil table is given and based on this the plot for the relative permeability curve is drawn. The plot looks like this.

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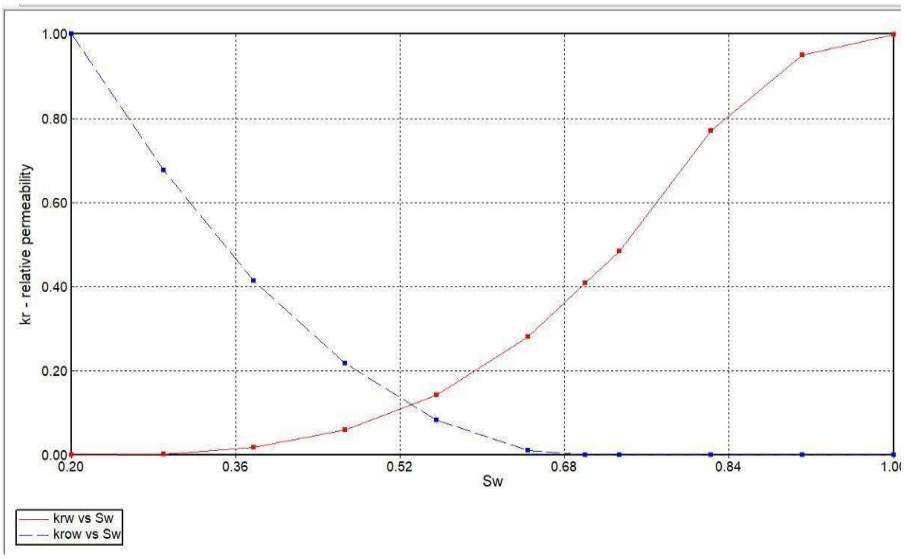


Figure 5. The Plot for water-wet oil water system.

This plot shows a water-wet oil–water system, where oil flow dominates at low Sw, both phases flow at intermediate Sw, and water dominates at high Sw, with oil becoming immobile beyond residual oil saturation—critical for predicting waterflood and EOR performance. Overall, the relative permeability characteristics play a crucial role in controlling multiphase flow behavior, sweep efficiency, water breakthrough timing, and ultimate oil recovery in reservoir simulation studies.


Figure 6. Initial conditions applied at the block saturation at each Block.

This number is an indication of the Block Saturation at each grid block with depth (VERTICAL DEPTH AVE) option chosen with saturations being an average that is determined in relation to the vertical depth of each grid block. Initialization of the reservoir is made on the condition that phases of Water-Gas (WATER GAS) occur. WaterGas zone transition modeling is disregarded (NOTRANZONE), which means that effects of capillary pressure transition are not taken into account. The Phase pressure correction (EQUIL) enables the reservoir to be in gravitational equilibrium when the process starts. Other options such as block-center saturation initialization, user-specified pressures and saturations are provided but not selected.

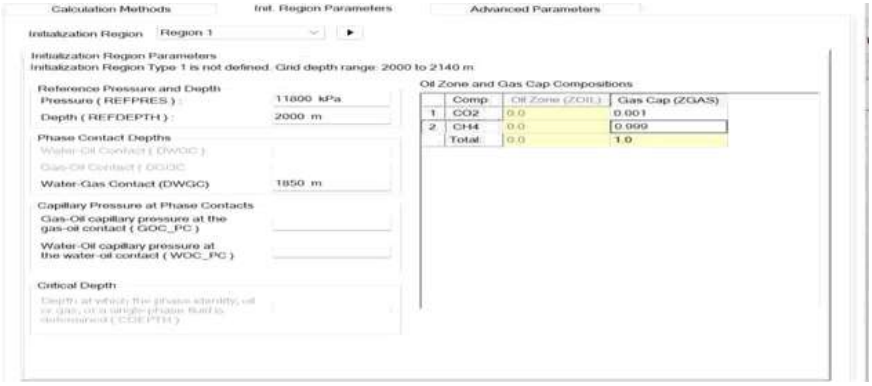


Figure 7. Region parameters Initialization and adding of the components Reference pressure is set to 11,800 kPa at a reference depth of 2000Psi

The base pressure for hydrostatic pressure calculation. The water–gas contact depth (DWGC) is defined at indicating the interface Capillary pressure effects at phase contacts are not specified, implying phase The oil zone and gas cap compositions are defined using component fractions:
Methane ($CH_4$) is the dominant component in the gas cap with a mole fraction of 0.999.Carbon dioxide ($CO_2$) contribution is negligible. The total composition confirms a pure gas-dominated cap, while the oil zone composition is set to zero

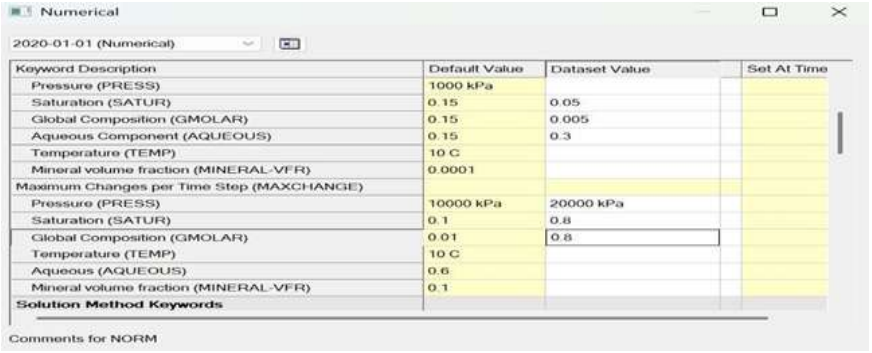


Figure 8. Creating a default and Dataset value

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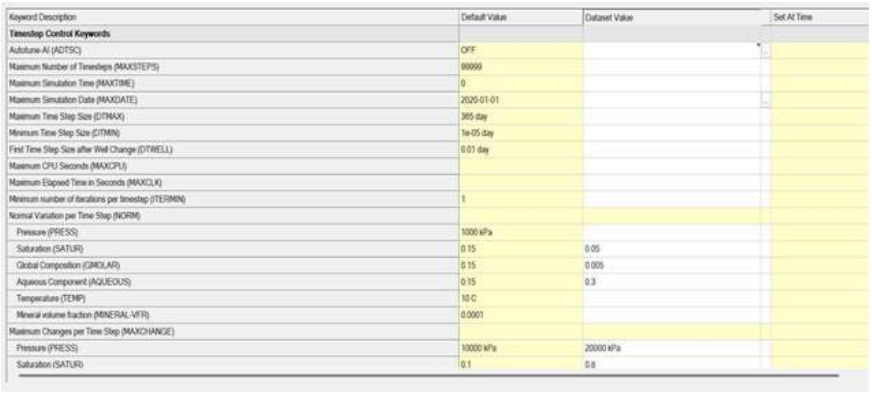
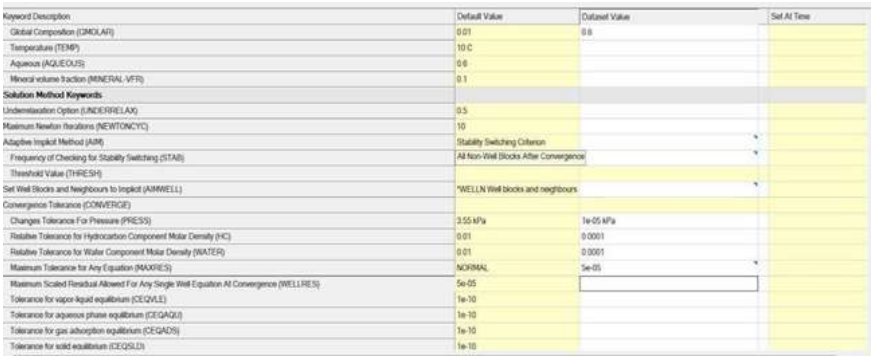
This figure shows the Numerical Control settings used in the reservoir simulation model. These parameters control solution stability and convergence. Limits are defined for pressure (PRESS) and saturation (SATUR) changes to ensure numerical stability. The default pressure change is set to 1000 kPa, while the maximum allowable pressure change is increased. Saturation limits are adjusted from a default value of 0.15 to 0.8, allowing wider saturation variation.



| Keyword Description | Default Value | Dataset Value | Set At Time |
|---|---|---|---|
| **Timestep Control Keywords** | | | |
| Autotune AI (ADTSC) | OFF | | |
| Maximum Number of Timesteps (MAXSTEPS) | 99999 | | |
| Maximum Simulation Time (MAXTIME) | 0 | | |
| Maximum Simulation Date (MAXDATE) | 2020-01-01 | | |
| Maximum Time Step Size (DTMAX) | 365 day | | |
| Minimum Time Step Size (DTMIN) | 1e-05 day | | |
| First Time Step Size after Well Change (DTWELL) | 0.01 day | | |
| Maximum CPU Seconds (MAXCPU) | | | |
| Maximum Elapsed Time in Seconds (MAXCLK) | | | |
| Minimum number of iterations per timestep (ITERMIN) | 1 | | |
| Normal Variation per Time Step (NORM) | | | |
| Pressure (PRESS) | 1000 kPa | | |
| Saturation (SATUR) | 0.15 | 0.05 | |
| Global Composition (GMOLAR) | 0.15 | 0.005 | |
| Aqueous Component (AQUEOUS) | 0.15 | 0.3 | |
| Temperature (TEMP) | 10 C | | |
| Mineral volume fraction (MINERAL-VFR) | 0.0001 | | |
| Maximum Changes per Time Step (MAXCHANGE) | | | |
| Pressure (PRESS) | 10000 kPa | 20000 kPa | |
| Saturation (SATUR) | 0.1 | 0.8 | |

Figure 9. Creating time step control keywords

This figure presents the time-step control and numerical stability parameters used in the reservoir simulation
Explanation: Automatic timestep tuning (ADTSC) is turned OFF, indicating manual control over timestep size. The maximum number of timesteps (MAXSTEPS) is set to 99,999, allowing long-term simulation The simulation start date (MAXDATE) is defined as 01-01-2020, and the maximum simulation time (MAXTIME) The maximum timestep size (DTMAX) is limited to 365 days, while the minimum timestep size (DTMIN)



| Keyword Description | Default Value | Dataset Value | Set At Time |
|---|---|---|---|
| Global Composition (GMOLAR) | 0.01 | 0.8 | |
| Temperature (TEMP) | 10 C | | |
| Aqueous (AQUEOUS) | 0.6 | | |
| Mineral volume fraction (MINERAL-VFR) | 0.1 | | |
| **Solution Method Keywords** | | | |
| Underrelaxation Option (UNDERRELAX) | 0.5 | | |
| Maximum Newton Iterations (NEWTONCYC) | 10 | | |
| Adaptive Implicit Method (AIM) | Stability Switching Criterion | | |
| Frequency of Checking for Stability Switching (STAB) | All Non-Well Blocks After Convergence | | |
| Threshold Value (THRESH) | | | |
| Set Well Blocks and Neighbours to Implicit (AIMWELL) | *WELLN Well blocks and neighbours | | |
| Convergence Tolerance (CONVERGE) | | | |
| Changes Tolerance For Pressure (PRESS) | 3.55 kPa | 1e-05 kPa | |
| Relative Tolerance for Hydrocarbon Component Molar Density (HC) | 0.01 | 0.0001 | |
| Relative Tolerance for Water Component Molar Density (WATER) | 0.01 | 0.0001 | |
| Maximum Tolerance for Any Equation (MAXRES) | NORMAL | 1e-05 | |
| Maximum Scaled Residual Allowed For Any Single Well Equation At Convergence (WELLRES) | 5e-05 | | |
| Tolerance for vapor-liquid equilibrium (CEQVLE) | 1e-10 | | |
| Tolerance for aqueous phase equilibrium (CEQAQU) | 1e-10 | | |
| Tolerance for gas adsorption equilibrium (CEQADS) | 1e-10 | | |
| Tolerance for solid equilibrium (CEQSLD) | 1e-10 | | |

Figure 10. Creating a keyword description and mentioning the dataset value

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This figure presents the solution method keywords and convergence criteria used in the numerical simulation. Explanation: The global composition (GMOLAR) is set to 0.8, defining the overall molar fraction used in the compositional as the simulation is carried out under isothermal conditions with the temperature fixed at 10 °C. The under-relaxation factor (UNDERRELAX) is set to 0.5 to improve numerical stability during nonlinear A maximum of 10 Newton iterations (NEWTONCY) is allowed per timestep to ensure convergence.

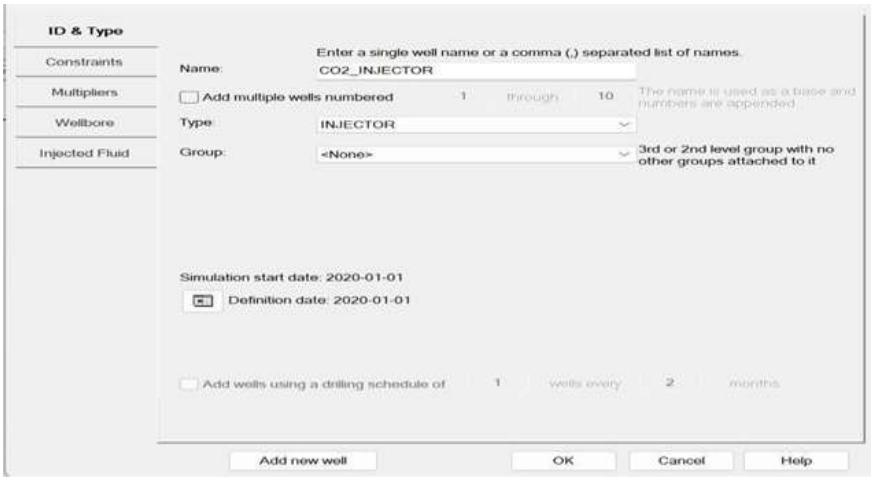


Figure 11. Well creation interface used to define $CO_2$

This figure shows the well creation interface used to define a $CO_2$ injector well in the reservoir , Explanation: A new well named CO2_INJECTOR is created and classified as an injector well. The well is not assigned to any group, indicating it operates independently within the simulation. The simulation start date and well definition date are both set to 01-01-2020, ensuring injection No multiple-well numbering or drilling schedule is applied, implying a single, manually defined. This configuration enables controlled $CO_2$ injection into the reservoir for enhanced recovery.

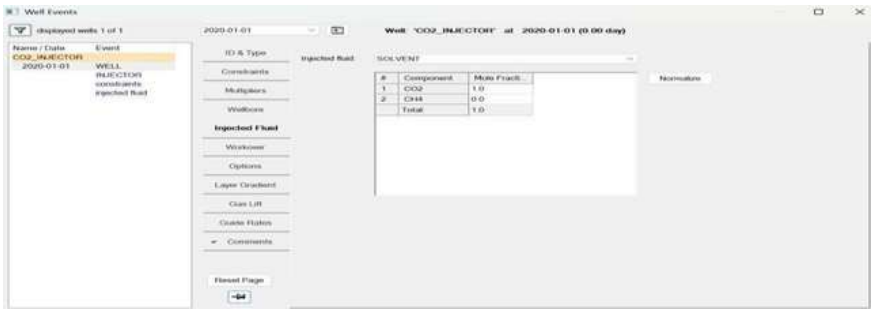

Figure 12. Adding the injected fluid values based on components

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Injected fluid specification for the $CO_2$ injector well defined in the reservoir simulation model. The injected fluid type is specified as solvent, indicating compositional injection rather than simple water or gas injection. The injected fluid composition consists of 100% carbon dioxide ($CO_2$) with a mole fraction of 1.0. Methane ($CH_4$) is assigned a mole fraction of 0.0, confirming the absence of hydrocarbon gas in the injected stream. The total mole fraction is normalized to 1.0, ensuring correct compositional balance. The injection event is scheduled at the simulation start date 01-01-2020.


Figure 13. Selection of the reservoir variables to be included in the simulation results

This Figure Shows the Selection of Reservoir Variables to Be Included in The Simulation Results Output File. A Wide Range of Rock, Fluid, And Flow Properties Are Available for Selection, Including Bulk Volume, Capillary Number, And Compressibility Parameters. Density-Related Variables Such as Gas Density (DENG), Oil Density (DENO), And Water Density (DENW) Are Selected to Analyze Fluid Behavior Under Reservoir Conditions. Pressure-Related Outputs, Including Datum Pressure (DATUMPRES) And Pressure Drop (DROP), Are Included to Monitor Pressure Distribution and Depletion. Flow-Related Variables Such as Fluid Enthalpy (FLUIDH) And Flux Across Grid Block Connections (FLUXCON) Are Selected for Evaluating Flow Dynamics.

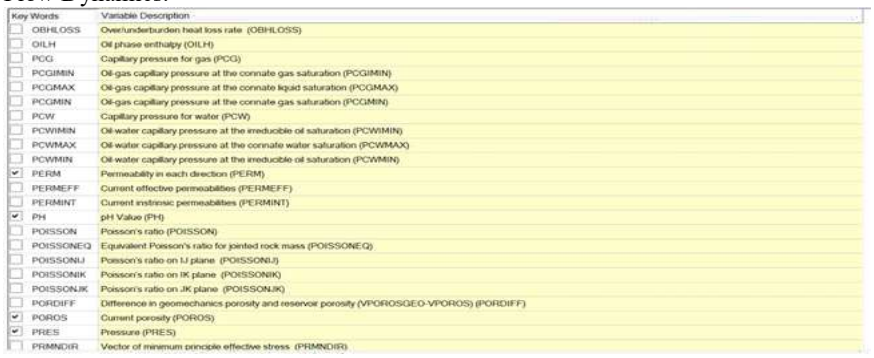


Figure 14. selecting the variables for Simulation Results File

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This image shows a "Select Variables for Simulation Results File" window from a reservoir simulation software, likely CMG (Computer Modelling Group) Builder. This interface allows a reservoir engineer to choose which physical properties and calculation results should be exported to the output file after the simulation run is complete. These outputs are used later for visualization (like 3D maps) and performance analysis. Selection Checkboxes: Variables with a checkmark (like PERM, PH, POROS, and PRES) are currently selected to be recorded in the results file.: Only the variables with a checkmark will be saved at each time step during the simulation run.

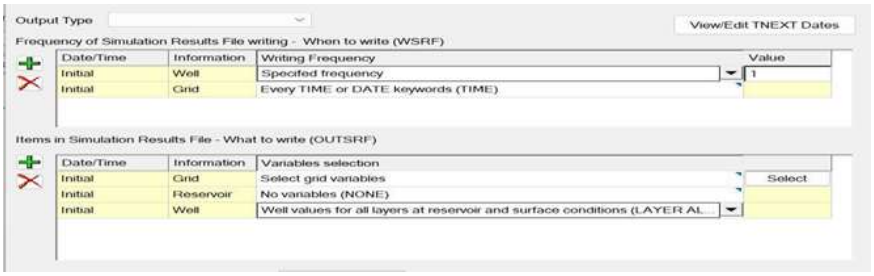


Figure 15. Mentioning the simulation files and variables

This image shows the Select Variables for Simulation Results File window in CMG Builder, which is a reservoir simulation pre-processor. This window is essentially a "shopping list" where you tell the simulator which specific physical properties it needs to record and save for every grid block at every step. If a variable is not checked here, you will not be able to visualize it in 3D once the simulation is finished. Key Components of the Window

## V. Results and Discussion

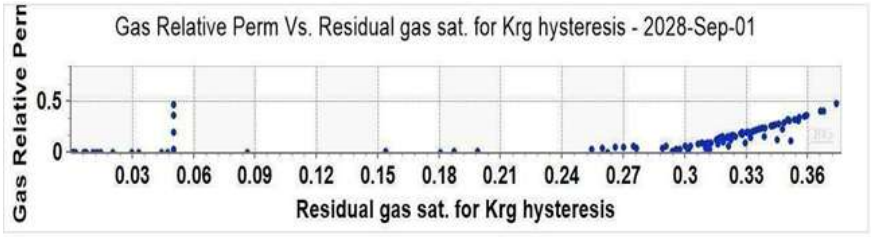


Figure 16. Krg vs Residual gas saturation snap-

Observation 1: Near-Zero Krg at Low Residual Gas Saturation Interpretation:
Gas is immobile at low residual gas saturations. This indicates strong residual (hysteretic) trapping of $CO_2$ after imbibition. Which means gas will be in contact with the oil for a long time so sweeping efficiency will increase
Observation 2: Transition Zone (~0.25–0.30) Interpretation:
Some grid blocks are transitioning from trapped gas to partially mobile gas

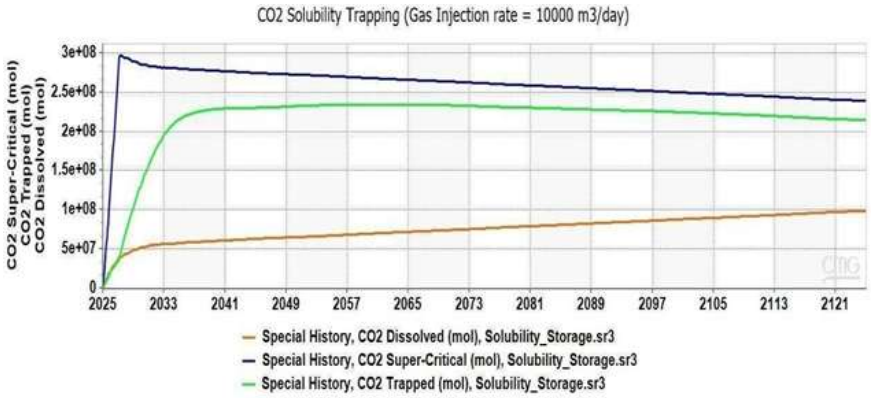


Figure 17. Solubility trapping of the injected carbon

Observation 1: Rapid Early Rise in Super-Critical $CO_2$. Indicates fast accumulation of injected
$CO_2$ in free, super-critical form
Interpretation: Early injection dominates, and $CO_2$ initially exists as a mobile phase before
significant dissolution occurs.
Observation 2: Progressive Increase in Dissolved $CO_2$
Interpretation: $CO_2$ continuously dissolves into formation brine, representing long-term solubility trapping.

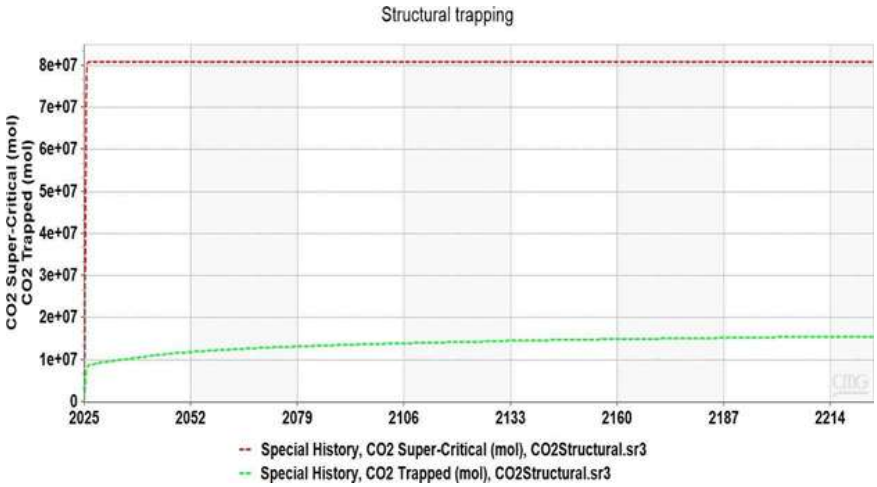


Figure 18. Special history plot

**Observation 1:** Very Rapid Early Increase in Super-Critical $CO_2$

Interpretation: Injected $CO_2$ rapidly migrates upward due to buoyancy and becomes structurally trapped under the caprock. Once the structural closure is filled, additional $CO_2$ does not significantly increase mobile super-critical volume.

**Observation 2:** Gradual Increase in Trapped $CO_2$ with Time
Interpretation: This represents secondary trapping mechanisms acting within the structure.

The structural trapping plot shows a rapid early accumulation of super-critical $CO_2$ beneath the caprock, indicating efficient buoyancy-driven migration and containment within the structural closure. The near-constant super-critical $CO_2$ volume at later times suggests that the trap reaches its capacity early, while the gradual increase in trapped $CO_2$ reflects continued immobilization through capillary and hysteresis effects. This sustained containment of $CO_2$ maintains reservoir pressure, improves sweep efficiency, delays gas breakthrough, and contributes to a 5–10% incremental increase in oil recovery in the CMG simulation.

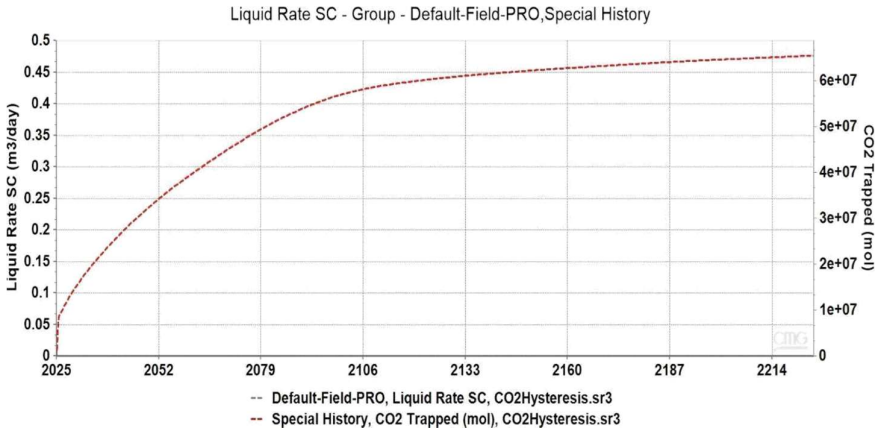


Figure 19. Liquid rate plot of Trapped $CO_2$ over time

The increasing trend of trapped $CO_2$ with time indicates strong hysteresis trapping, resulting from repeated drainage–imbibition cycles. The progressive immobilization of $CO_2$ reduces gas mobility and delays breakthrough, as reflected by the stable liquid production rate. This enhanced microscopic and macroscopic sweep efficiency leads to an incremental increase in oil recovery, typically in the range of 3–8% OOIP in CMG simulations.

## VI. Conclusion

This study evaluated the potential for increased oil recovery through $CO_2$ injection in a mature hydrocarbon reservoir using reservoir simulation with CMG-GEM. We developed a solid simulation framework. We started with detailed data processing, building static and dynamic models, characterizing fluids, tuning the EOS, and matching history

reliably for the base case. This laid a strong foundation for identifying and measuring the real impact of $CO_2$ injection on reservoir performance. Simulation results show that $CO_2$ injection significantly improves oil recovery compared to conventional depletion and waterflooding. Miscible $CO_2$ injection at pressures equal to or above the Minimum Miscibility Pressure (MMP) yielded the highest incremental recovery due to reduced oil viscosity, oil swelling, and improved microscopic displacement efficiency. We set out to see how much more oil we could pull from a mature reservoir by injecting $CO_2$, and we used CMG-GEM to run our simulations. First, we put together a solid framework: lots of data wrangling, building both static and dynamic models, getting our fluid characterization right, tuning the EOS, and making sure our history match for the base case was solid. That groundwork let us really see what $CO_2$ could do for the reservoir.

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