Rapid Prediction of CO_2 Movement in Aquifers, Coal Beds, and Oil and Gas Reservoirs

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If greenhouse gas (e.g., CO_2) injection into geologic formations is undertaken on a large scale, physically-accurate and high-resolution, but low computational cost, numerical methods are needed. Such simulations will be used to predict where CO_2 is likely to flow, interpret the volume and spatial distribution of the subsurface contacted by injectant, and optimize injection operations. Such elements are essential if geological sequestration is to be proven feasible and public acceptance is to be gained.

Simulating CO_2 flow behavior in geologic media is difficult because of the interplay between phase behavior, composition, reservoir heterogeneity, and the computational demands these aspects impose. Nevertheless, simulation is vital role to design storage schemes and evaluate uncertainty. For example, a reservoir permeability field is never known with any certainty and the flow behavior of several different realizations of geology must be computed to gauge the range of possible behavior. Fully-compositional, finite-difference simulation techniques are notoriously slow, especially when grid dimensions are made sufficiently fine to begin to resolve the coupling between flow and phase behavior . Streamline methods hold great promise for aiding the design of efficient injection and storage processes. Streamline methods are based on the idea that the flow can be represented by a series of 1D displacements along streamlines or streamtubes. Thus, the dimensionality of the problem is reduced greatly. A streamline is tangent everywhere to the instantaneous velocity field and perpendicular to isopotential lines. The effects of heterogeneity and evolving flow paths are captured by the locations of streamlines. The physical and chemical mechanisms of the displacement are captured in detail by the 1D flow model.

Demonstration of Capabilities:

In this study, we are developing ultra-fast computational methods and tools applicable to the suite of geologic formations suitable for greenhouse gas storage. The underpinnings of these methods are streamline-based computations. A variety of research is underway that is applicable to the problem including the effect of gravity in the simulation of CO_2 into saline aquifers, inclusion of capillary effects, using CO_2 to enhance condensate recovery, and simultaneous optimization of oil recovery and CO_2 storage. Our capabilities and the current state of research are described next.

Effects of Gravity:

A new method for including gravity effects in compositional streamline simulation was recently developed. The method makes use of operator splitting to account for both pressure driven and gravity induced multiphase flow. It is implemented in the research code compositional streamlines simulator (CSLS) of the PE department. CSLS forms the basis for the development of an efficient and accurate tool for prediction of flow performance during CO_2 injection in saline aquifers.

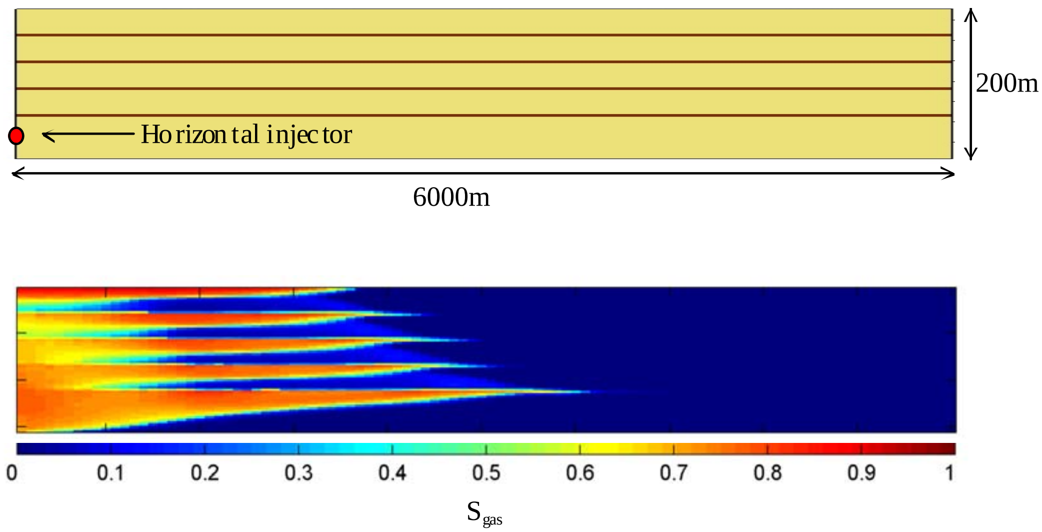


Figure 1. Simplified model of the Utsira formation (top). Low permeability shales are darkly shaded and high perm sands are light. Prediction (lower) of CO_2 distribution after 2 years of injection.

Figure 1 presents example results from CSLS including gravity. Figure 1a gives the layout of the two-dimensional simulation geometry representative of the flow around a long horizontal injector. The two-dimensional geometry is chosen solely for illustration purposes. Low permeability shales are represented as thin, dark lines, whereas sand is lightly shaded. The geometry is a highly idealized representation of the geology at the Sleipner, CO_2 injection site in the North Sea[1]. Figure 1b illustrates the distribution of CO_2 predicted by CSLS after two years of injection at rates similar to those at Sleipner. Note the collection of the more buoyant CO_2 beneath the shale zones. The seal on the aquifer is assumed to be impermeable and, consequently gas saturation predicted there is high.

Specific timings of the speed up offered by this approach have not been conducted as of yet. Nevertheless, this particular two-dimensional example requires only 50 inversions of the pressure matrix, whereas a commercial finite difference method requires 500 pressure solves using an AIM method and 2000 pressure solves using an IMPES formulation. We speculate that in three-dimensional simulations the speed up factor will be 10.

Effects of Capillarity:

In related work, we have developed in collaboration with the IVC-SEP research group (Department of Chemical Engineering, Technical University of Denmark) a method for the introduction of capillary forces into a streamline simulator. Capillary effects are responsible for the phase pressure difference between wetting and nonwetting fluids. They may alter significantly the displacement character, especially, in low permeability and heterogeneous porous media. The new method is based on a recently introduced capillary-viscous potential, which is used instead of the phase pressures during solution of the pressure equation. To date the work has been oriented

[1] Pruess, K., A. Bielinski, J. Ennis-King, R. Fabriol, Y. Le Gallo, J. García, K. Jessen, A. R. Kovscek, D. H.-S. Law, P. Lichtner, C. Oldenburg, R. Pawar, J. Rutqvist, C. Steefel, B. Travis, C.-F. Tsang, S. White, T. Xu, "Code Intercomparison Builds Confidence in Numerical Models for Geologic Disposal of CO_2, paper 82, Proceedings of the Sixth International Conference on Greenhouse Gas Control Technologies (GHGT-6), Kyoto, Japan, Oct. 2002.

toward prediction of the flow of oil and water and is quite encouraging. The formulation requires 5 to 10 times fewer pressure updates as compared to finite-difference simulation.

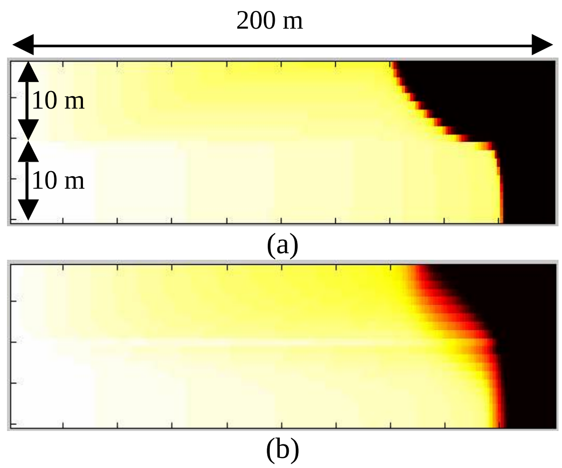


Figure 2. (a) Displacement front without accounting for capillarity. (b) Displacement front with capillary effects. Light shading is water and dark is oil.

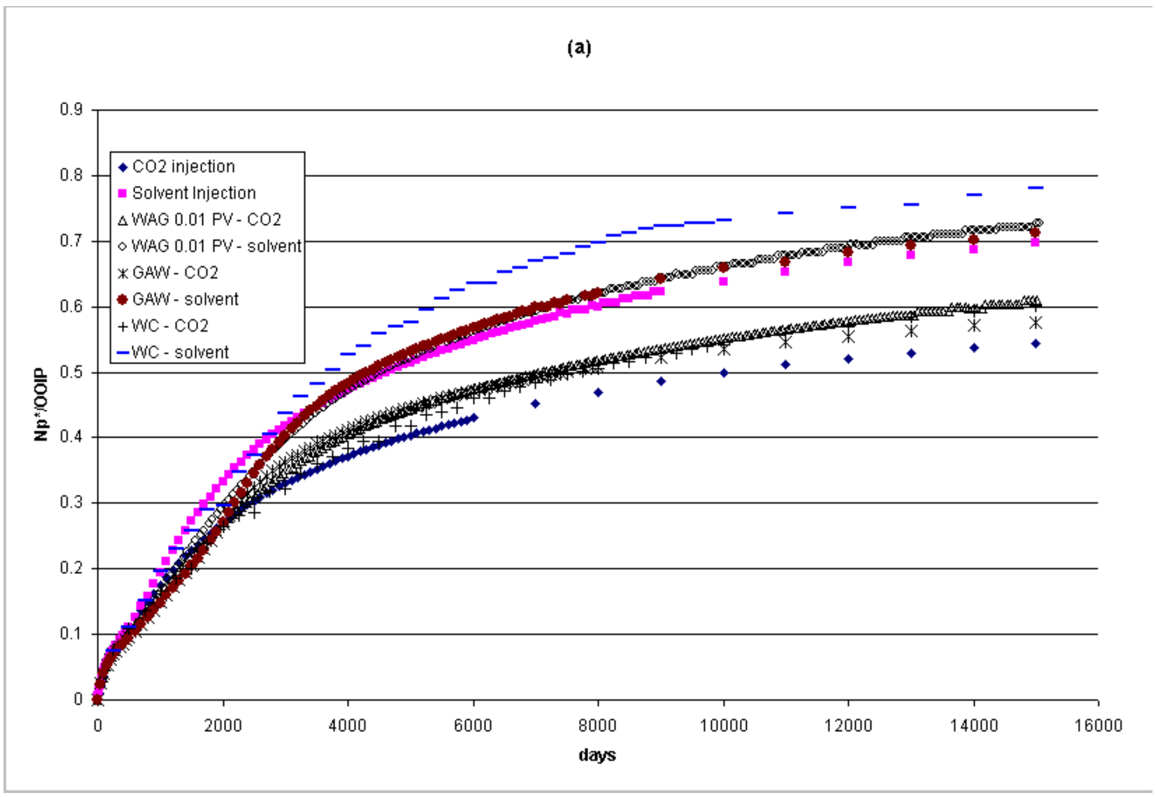
Figure 2 illustrates the introduction of capillary effects during water flooding in a two-dimensional two layer oil reservoir. The elapsed time is 0.3 PVI. The top layer is less permeable than the bottom. White shading represents water and dark shading represents oil. Injection is across the entire left side. Figure 2b demonstrates greater sweep and the delayed breakthrough time, with respect to conventional finite difference simulation.

Carbon dioxide is well known to enhance the recovery of hydrocarbons. We are studying techniques to maximize the use of CO_2 during enhanced oil recovery (EOR) and streamline methods for predicting the improvement of gas recovery from gas-condensate fields accompanying CO_2 injection.

EOR and Sequestration: The design question for combined EOR and sequestration is significantly different than EOR alone. For pure EOR, one attempts to maximize oil recovery while injecting minimum CO_2 and this is accomplished by injecting a fair amount of water in a water-alternating gas fashion. In combined sequestration and EOR one maximizes both oil recovery and the amount of reservoir volume filled with CO_2. This is so-called cooptimization. Our cooptimization efforts are currently focused on (1) exploring injection-production techniques that meet the new design criteria and produce at least as much oil as conventional recovery efforts and (2) expanding the range of candidate reservoirs considered for CO_2 injection.

Figure 3 compares the performance of various reservoir development scenarios that might be used during CO_2 sequestration in oil reservoirs. The reservoir model is a realistic 3D, heterogeneous, and stochastic description including a 15 component reservoir fluid. Reservoir shape is anticlinal and it is bounded by faults and an aquifer. The description of heterogeneities and their distribution is geostatistical in that multiple reservoir models are generated capturing variability and uncertainty. There are four injectors near the flanks of the reservoir and 4 producers near the crest. The reservoir does not represent a typical CO_2 injection candidate: the oil is relatively heavy (24 °API) and pure CO_2 is not miscible in the crude oil at reservoir pressure. Scenarios have used pure CO_2 as an immiscible injection gas and a solvent gas composed of about 2/3 by mole CO_2. Figure 3 compares water-alternating-gas (WAG) drive mode with immiscible and miscible gas injection, gas injection after waterflood (GAW), and gas-controlled production (WC). The first two scenarios are designed so that the mobilities of the injected phases in the reservoir are reduced. In the last scenario, production wells are actively controlled to limit the amount of produced gas and increase the contact of gas with reservoir volume. Control parameters are the producing gas-oil ratio (GOR) and the injection pressure. In all cases, oil production is discounted by the equivalent amount of energy needed to compress produced gas. Schemes that incur excessive gas cycling pay a penalty with respect to oil production.

As Figure 3(a) shows, oil recovery is greatest as a result of miscible gas injection. With miscible gas injection, the local displacement efficiency approaches unity and recovery is maximized. Among the scenarios with miscible gas injection, well-controlled injection resulted in oil recovery 7 to 12 % greater than the other cases and approaches 80% of the oil in place. In the case of pure CO_2 injection, WAG with small equal-sized slugs (0.01 pore volume) of water and CO_2 performs the best, however ultimate recovery is nearly the same as well-controlled CO_2 injection. The main differences between these two scenarios are found during intermediate portions of the recovery lying between 3000 and 7000 days.



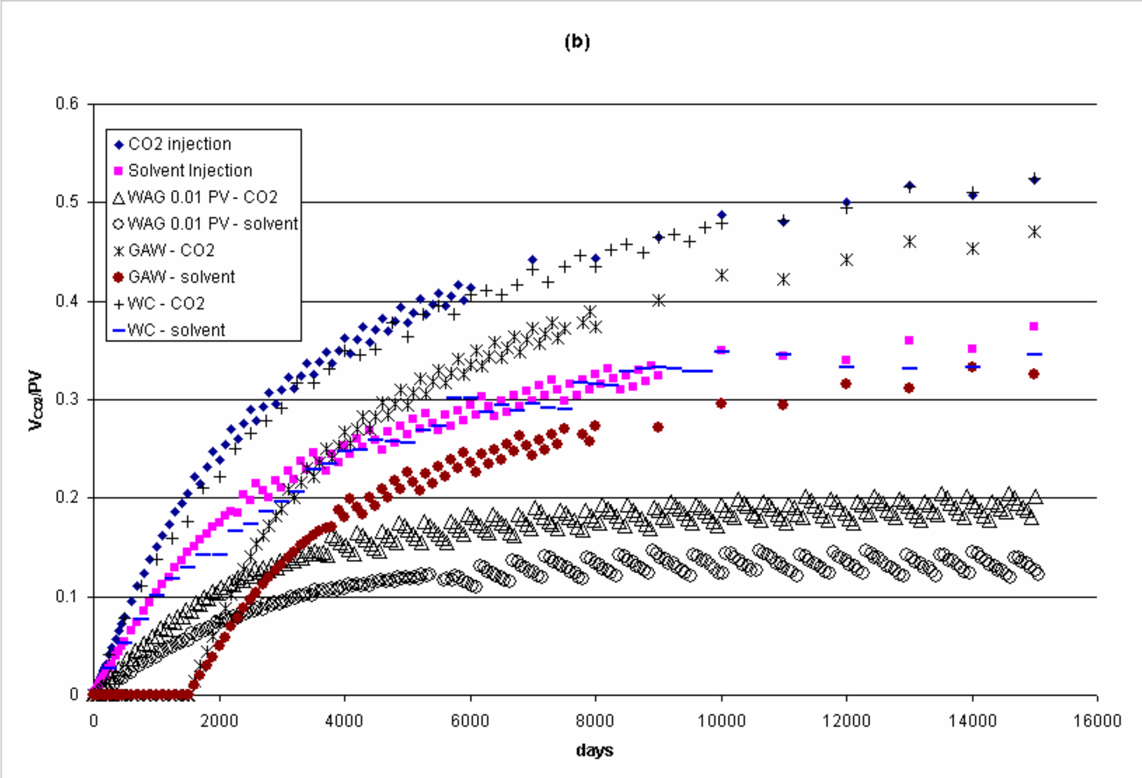


Figure 3. (a) Oil Recovery and (b), and reservoir utilization performance of different gas injection processes from a 3D, compositional reservoir example.

In Figure 3(b), the injection scenarios are compared with respect to the reservoir volume utilized. In this case, immiscible CO_2 injection cases perform better than miscible solvent injection because only two thirds of the solvent gas is CO_2. All cases illustrate that injection of water for mobility control frustrates sequestration. Pore space becomes filled with water when it otherwise could be filled with CO_2. Gas-controlled production appears promising. Oil production obtained from pure CO_2 injection with well control is on par with that obtained in an optimized WAG process while the utilization of reservoir volume to store CO_2 is about 2.5 times that of a WAG scheme. In general, gas-controlled production appears to limit gas cycling while increasing oil production and CO_2 storage by 12 to 20% as compared to injecting pure CO_2 or solvent gas.

Gas Condensate and CO_2 Utilization:

Gas cycling schemes for condensate recovery are inherently compositional. In order predict performance, compositional simulation is necessary. Efficiency of enhanced recovery schemes is dependent on two factors:

- local displacement efficiency that is controlled by phase behavior of mixtures of injection gas and fluid in the reservoir. Fluid description must adequately capture fluid PVT and dilution behavior. Condensate behavior is sensitive to heavy components. To model retrograde behavior in a gas injection scheme, high resolution is required in the heavy end of the fluid description.
- global sweep efficiency that is controlled by reservoir heterogeneity. High mobility injection gas flow preferentially through high permeability paths in the reservoir, efficiently displacing condensate in these regions while bypassing condensate in low permeability zones. Extremes in permeability have significant impact in determining fluid flow.

Compositional finite difference (FD) simulation is the conventional way to model these systems. In this method, a material balance for each component, over each block, must be calculated. Included in this calculation is at least one flash per grid block per time step. For large models or complex fluid descriptions, computational times are prohibitively slow. In order to obtain results in a reasonable time, simplifications in fluid description and reservoir heterogeneity are necessary potentially rendering results inaccurate. An alternative to FD simulation is compositional SL simulation. In this method, compositions are propagated as 1D displacements along streamlines. Coupling streamlines with the fast analytical solutions of the displacement, simulation times are reduced by orders of magnitude.

In order to model fluid displacements along streamlines, a few assumptions are made:

- no gravity or viscous crossflow. In condensate systems, the density difference between injected gas and reservoir gas is small. As a result, mobility differences are also small, and it can be assumed that the streamlines remain as fluids propagate through the reservoir.
- no capillary forces. Fluids in condensate systems are critical, and interfacial tensions are expected to be low. During gas injection in condensate systems, gas displaces gas.
- no physical dispersion. On the reservoir scale, convective forces are orders of magnitude larger than dispersive forces. Convection is the dominant force propagating gas from injector to producer.

There is a balance between technical and economic factors, with respect to the recovery of condensate from retrograde reservoirs. Recovery of liquids must be maximized while minimizing costs associated with operating a gas injection scheme. In many operations, the costs associated with deferred gas production versus the value of incremental condensate recovered make such schemes uneconomic. As with enhanced oil recovery, CO_2 is very effective at condensate recovery. In many cases, surface forces render the condensate immobile, and the only means to recover efficiently these hydrocarbons is through vaporization into a mobile phase. An analytical solution for the recovery of a condensate using 100% CO_2 is shown in Figure 4. Condensate is recovered through a series of vaporizing shocks. Analytical solutions are mapped along streamlines to obtain a powerful tool for quick assessments of gas injection schemes for condensate vaporization.

Figure 4 compares gas saturation profiles for the analytical solution and corresponding 1D FD simulations of varying resolution between injector and producer. The FD method approaches the SL solution for resolutions greater than 1000 grid blocks between injector and producer. In practice, such fine resolution is never modeled during field-scale simulation.

Table 1 compares simulation times of compositional FD and SL simulation. Figure 5 demonstrates that the SL method yields results comparable to the FD method. The speed-up factors afforded by SL simulation allow one to model gas injection schemes for enhanced condensate recovery in multiple, detailed, field-scale models. Recall, that the amount of hard data relative to the volume of the subsurface is small and multiple equiprobable geological models can be constructed that are consistent with hard data. The speed up of calculations implies that screening of multiple geological realizations and Monte Carlo analysis can be performed, mitigating risk and reducing uncertainty surrounding injected fluid location during the project life.

Table 1. Comparison of FD and SL simulation times.

Model Size	FD (s)	SL (s)	Speed Up Factor

5 000	7406	14	499
13 500	38991	24	1624
5 774	4446	19	234
600 000	N/A	1914 (for 1 PV injected)	

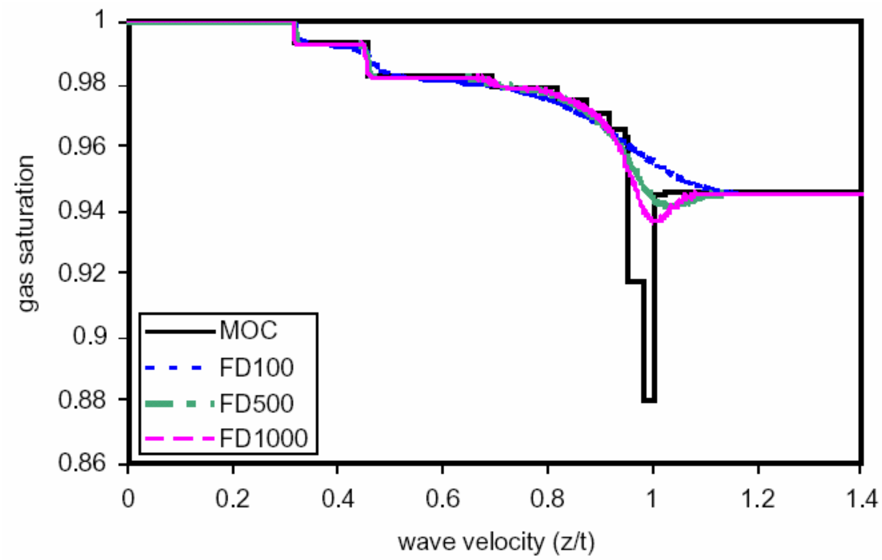


Figure 4. Analytical solution and FD simulations of various resolution between injector and producer.

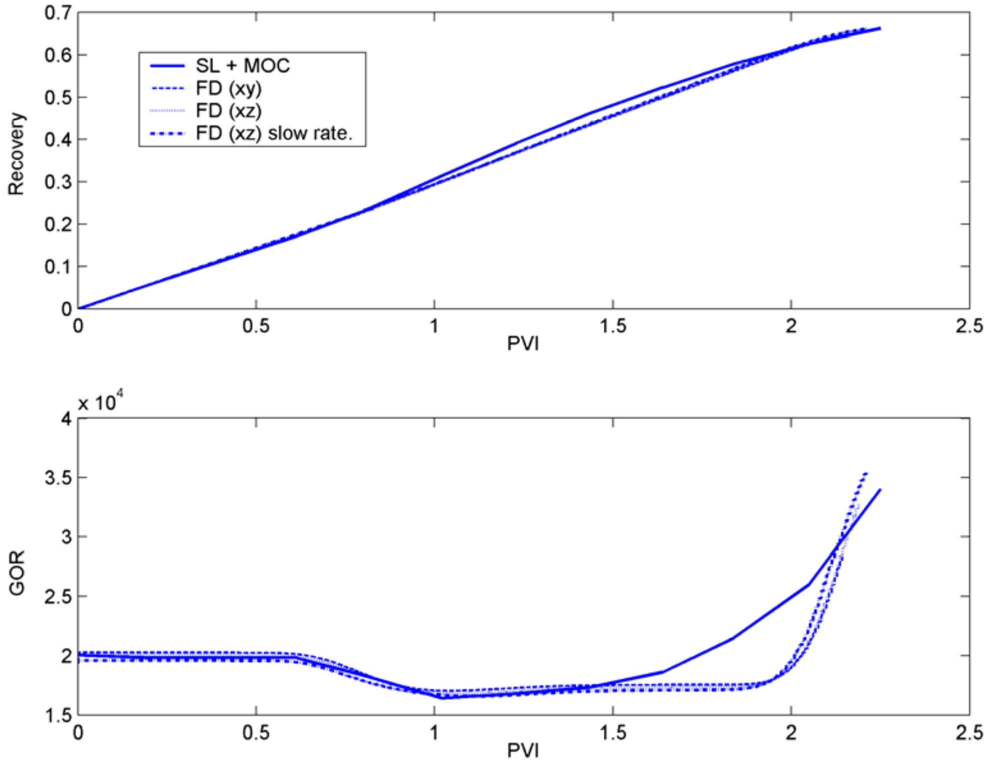


Figure 5. SL method gives results comparable to FD method.

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