



Performance Evaluation of Immiscible Water Alternating Gas Injection Using Integrated Asset Modelling

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Abstract

Integrated evaluation of enhanced oil recovery (EOR) performance in offshore reservoirs requires consideration of surface constraints that can limit well deliverability and field production. Immiscible water alternating gas (IWAG) injection is often assessed using standalone reservoir simulation, which does not explicitly represent interactions among the reservoir, wells, and surface facilities. This study applies an integrated asset modelling (IAM) framework to evaluate IWAG performance under operational constraints and compare it with a reservoir-only simulation. A three-dimensional reservoir model was simulated using both approaches under identical subsurface conditions. The unconstrained reservoir-only case forecast approximately 19% higher cumulative oil over the 30-year evaluation period than the IAM case. Within IAM, sensitivity analyses were performed on injection rate and cycle duration. W2G3 with an 18-month cycle was the best-performing configuration among those tested, producing 162.18 MMSTB of cumulative oil, increasing recovery factor from 13.0% to 16.0%, and adding 34.53 MMSTB of incremental oil. The results show that production forecasts are sensitive to whether well and surface constraints are represented explicitly. For the conditions evaluated, IAM provides a more representative basis for IWAG screening and pilot planning than a reservoir-only model.

Keywords: *Enhanced Oil Recovery, Immiscible Water Alternating Gas, Integrated Asset Modelling, Reservoir Simulation, Water-Gas Injection.*

INTRODUCTION

Enhanced oil recovery (EOR) methods are used to extend oil recovery beyond the limits of primary and secondary production, particularly as fields mature and conventional recovery becomes less effective (Bealessio et al., 2021). Offshore application introduces additional technical and operational constraints because EOR performance must be compatible with existing wells, injection systems, and surface facilities (Poulsen et al., 2020). Among the available EOR methods, immiscible water-alternating-gas (IWAG) injection combines alternating water and gas slugs to improve gas mobility control and reduce early gas breakthrough. Experimental and numerical studies have shown that the process can redistribute residual oil and improve recovery when the injection design is suited to the reservoir conditions (Liu et al., 2021; Kong et al., 2021).

The performance predicted for IWAG also depends on how the production system is represented in the model. The conventional reservoir simulation often simplified the production system through fixed well constraints and surface facilities are not represented dynamically. This simplification may be acceptable for early screening, but it can overstate production in offshore developments, where pressure losses, facility capacities, and network bottlenecks often control both fluid flow and injection feasibility. Hamed Shokrlu et al. (2020) showed that standalone reservoir optimisation can give different results when facility limitations are excluded, while their

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integrated offshore model accounted for the reservoir and surface system simultaneously. Field experience reported by [Tan et al. \(2021\)](#) also showed that surface limitations, injection pressure, well downtime, and injectivity affected the execution of an offshore IWAG project.

Integrated asset modelling (IAM) addresses this interaction by coupling reservoir performance with wells and the surface network. Reservoir-network coupling has been used to account for backpressure and facility limits during field forecasting and well allocation ([Wiegand et al., 2021](#)). More recent integrated field studies have applied the same principle to development planning in systems where several reservoirs and wells operate through a common surface network ([Ryzhikov et al., 2025](#)). These applications provide a basis for evaluating an injection strategy under the same constraints that govern fluid movement from the reservoir to the processing facilities. This approach allows EOR strategies to be tested under operating conditions that are closer to field practice.

Previous IWAG studies have established its recovery potential under different reservoir and operating conditions. [Kong et al. \(2021\)](#) reported an incremental recovery of 15.62% for the best injection condition examined in a high water cut coreflood study, while [Liu et al. \(2021\)](#) reported recovery improvements of approximately 5 to 10% in a tight-oil IWAG study. Field applications have also demonstrated that IWAG performance depends on injection continuity, injectivity, available surface capacity, and surveillance strategy ([Tan et al., 2021](#); [Basri et al., 2025](#)). Most of these studies, however, focus on displacement behaviour, injection design, or field implementation. Fewer studies directly compare a reservoir-only forecast with an integrated reservoir-well-surface forecast while retaining the same subsurface model. This comparison is useful because the calculated incremental recovery can change when the baseline production forecast is subject to different operating constraints.

The reservoir model used in this study is a synthetic offshore model developed to represent the production and facility conditions considered in the IWAG pilot evaluation. Using this model, conventional reservoir simulation and IAM are compared under identical subsurface conditions over a 30-year forecast period. The study has three objectives: (1) to quantify the difference between an unconstrained reservoir-only production forecast and an IAM forecast that includes well and surface-system constraints; (2) to evaluate IWAG injection-rate and cycle-duration sensitivities within the IAM model; and (3) to identify the best-performing IWAG configuration among the cases tested and assess its production, recovery factor, VRR, and sweep response for pilot planning.

LITERATURE REVIEW

Immiscible water alternating gas (IWAG) injection combines gas displacement with water mobility control. Gas can move rapidly through high permeability intervals because of its lower viscosity and density, while the following water slug can reduce gas mobility and redirect flow toward less-swept regions. The effectiveness of this process depends on mobility ratio, gravity segregation, reservoir heterogeneity, injection ratio, and cycle duration ([Kong et al., 2021](#); [Liu et al., 2021](#); [Andersen et al., 2022](#)). These parameters form the basis for the injection-rate and cycle-duration sensitivities evaluated in this study.

WAG also introduces repeated drainage and imbibition as gas and water alternate in the pore space. Relative permeability therefore depends on saturation history rather than saturation alone. The trapping concept introduced by [Land \(1968\)](#) and the three phase relative permeability formulations proposed by [Stone \(1970\)](#) provide the basis for representing multiphase flow. [Larsen and Skauge \(1998\)](#), [Spiteri and Juanes \(2006\)](#), and [Shahverdi et al. \(2011\)](#) later showed that hysteresis can affect gas mobility, residual trapping, and predicted WAG performance. This behaviour is relevant when cycle duration is varied because each cycle changes the sequence of

drainage and imbibition.

At field scale, reservoir performance is also influenced by the well and surface system. Pressure losses in tubing and flowlines, manifold pressure, separator conditions, injection pressure, and facility capacities can limit the rates predicted by a reservoir-only model. Integrated asset modelling couples these components so that reservoir deliverability is evaluated together with network and facility constraints (Wiegand et al., 2021; Yadua & Lawal, 2023; Speranza et al., 2024; Ryzhikov et al., 2025). The approach is more computationally demanding and depends on the quality of well, network, and facility assumptions. Coupling stability can also become an issue when reservoir and surface models exchange pressure and rate information repeatedly.

IWAG field implementation adds constraints that are difficult to reproduce in laboratory studies. Gas supply, injectivity decline, compressor limits, corrosion, well downtime, and water-handling capacity can affect the feasible injection strategy (Tan et al., 2021; Hachem et al., 2022; Basri et al., 2025). Laboratory and reservoir-scale studies remain useful for understanding displacement mechanisms, but field performance depends on whether the injection design can be supported by the complete production system.

Study	Reservoir / Model	Gas	Injection Design	RF Gain	IAM
Kong et al. (2021)	Ultra-high-water-cut coreflood	N ₂	Cyclic IWAG	15.62%	No
Liu et al. (2021)	Tight-oil reservoir	CO ₂	Immiscible WAG	5–10%	No
Belazreg et al. (2021)	Numerical reservoir models	Hydrocarbon gas	Multiple IWAG cases	5–15%	No
Wang et al. (2021)	Long-core experiment	Flue gas	WAG after waterflooding	21.25%	No
Tan et al. (2021)	Mature offshore field	Field gas	Cyclic IWAG	Field-scale case	No
Andersen et al. (2022)	Heterogeneous numerical model	Immiscible gas	Multiple WAG ratios	Case dependent	No
Basri et al. (2025)	Mature offshore reservoir	Field gas	IWAG field development	Field-scale case	No
Rostami et al. (2026)	Coreflood, varying permeability	Associated gas	Immiscible / near-miscible WAG	Case dependent	No

METHODOLOGY

The simulations were performed using tNavigator reservoir simulation software. The workflow consisted of reservoir initialisation, well-placement optimisation, construction of the integrated reservoir, well and surface model, comparison of the reservoir-only base cases and IAM, and IWAG sensitivity analysis. The same reservoir description and selected well locations were retained throughout the forecast cases.

Reservoir Model Description

A three-dimensional synthetic offshore reservoir model was used for the study. The model represents a sandstone reservoir at approximately 2,500 m subsea and consists of one productive interval with aquifer-supported water-drive behaviour. The simulation grid contains $46 \times 112 \times 22$ cells, giving 113,344 total grid blocks and 104,970 active blocks.

Initial reservoir pressure was 3,942.1 psi, reservoir temperature was 192°F, and bubble-point pressure was 3,640.45 psi. The fluid model uses a black-oil PVT formulation with two PVT regions. Oil density is 53.65 lb/ft³, oil specific gravity is 0.85, API gravity is 34.97°, water viscosity is 0.318 cp, and oil viscosity is 0.693 cp and 0.855 cp for Rock Type 1 and Rock Type 2, respectively. Two sets of relative permeability and capillary pressure functions were assigned to the two rock types. Two rock types were represented using separate relative-permeability and capillary-pressure functions. Three-phase flow was calculated within the black-oil formulation using the assigned phase relative-permeability data. The IWAG process was treated as immiscible, and compositional miscibility effects were not modelled. Relative-permeability hysteresis sensitivity was not included in the present simulations; its potential effect on gas trapping and WAG performance is therefore acknowledged as a study limitation.

Initialisation

The model was initialised to reproduce the initial reservoir pressure and fluid distribution before production. The model was initialised to reproduce the prescribed initial reservoir pressure and fluid distribution before production. Since the model represents a synthetic greenfield reservoir with no production history, no history matching was performed. The initialised model was then used as the common subsurface basis for the reservoir-only, IAM, and IWAG forecast cases.

Key reservoir and in-place parameters used for model initialisation are summarised in Table 1. These inputs form the basis for comparing reservoir performance across different modelling approaches and recovery strategies.

Table 1. In-Place Values of Reservoir

Data	Value
Original Oil in Place, MMSTB	1011.94
Original Water in Place, MMSTB	2529.08
Original Gas in Place, MMSCF	955.47
Pore Volume, MMRBL	4234

Well Configuration and Field Development

The simulation model includes production and injection wells placed according to the existing field-development plan. The selected development consists of two vertical production wells, AJ_1 and AJ_5, and four vertical injection wells, INJ_1 to INJ_4. All wells were constructed in tNavigator Well Designer with casing, tubing, packer, and perforation intervals. Vertical Flow Performance tables were generated using the Hagedorn and Brown correlation, which accounts for hydrostatic, frictional, and elevation-related pressure losses along the wellbore.

Well trajectories, completion intervals, and spatial distribution were kept the same for all simulation cases. This approach ensures that any differences in performance are caused by the modelling method and injection strategy, rather than by changes in the well configuration.

Figure 1 shows the distribution of production and injection wells in the reservoir grid, including their positions relative to the reservoir structure and boundaries. The well locations and completions were not changed between the base case and the IWAG scenarios.

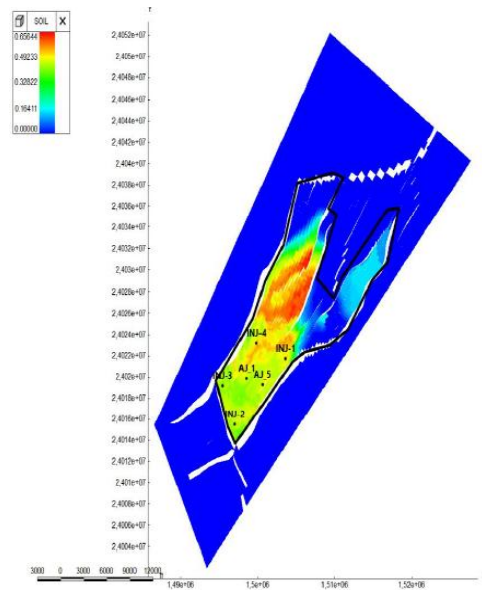


Figure 1. Well Placement Within Reservoir Model

Surface Facilities and IAM

The surface system was constructed using tNavigator Network Designer and included production flowlines, a manifold, a three-phase separator, production outlets, a pump, a compressor, a water source, and injection flowlines. The producer-side network and three-phase separator were operated at 350 psi. In the base case, the oil and water outlets were set at 50 psi and the gas outlet at 100 psi. For the IWAG case, the pump and compressor increased the injection-side pressure to 5,000 psi before the fluids were distributed to the injection wells. The AJ_1 and AJ_5 production flowlines were approximately 1,600 ft and 2,300 ft long, respectively, while the downstream line was represented by approximately 410,000 ft to the gathering point. Pressure losses through the wellbore and surface network were calculated dynamically within the coupled IAM model. Figure 2 presents the surface network and facility configuration used in the IAM model.

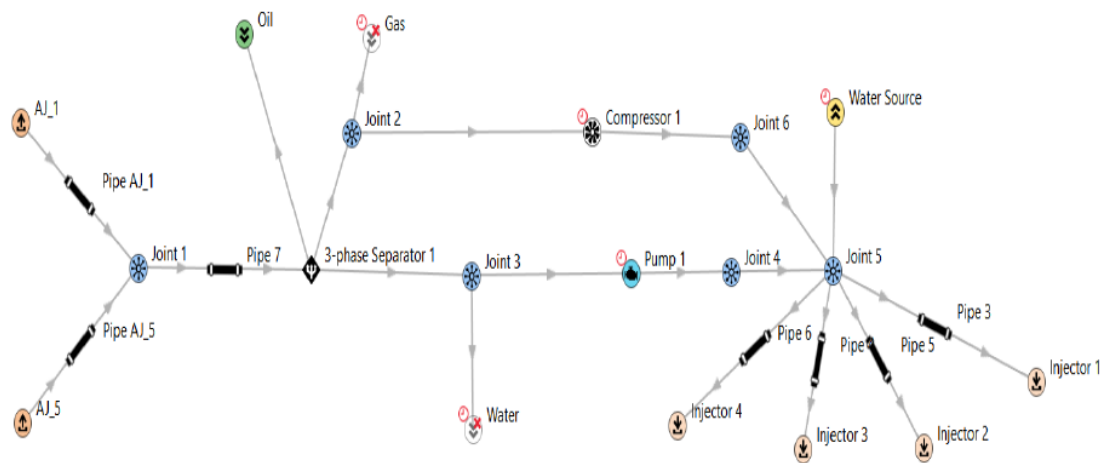


Figure 2. Network Design for IAM Base Case and IWAG Scenario

Base-Case Simulation Strategy

Both cases were evaluated over the same 30-year forecast period. A minimum production-well BHP constraint of 1,000 psi was applied, and no injection wells were active during the base-case simulation.

The second case used the same reservoir model, well locations, completion intervals, and forecast period, but the wells were connected to the IAM surface network. The difference between these two cases was therefore used to isolate the effect of IAM on the production forecast.

IWAG Injection Design and Evaluation

The well operated under natural flow conditions for the first 10 years, from 2025 to 2035. IWAG injection began in 2035, when reservoir pressure and production had declined from their initial levels. The injection period continued for the remaining 20 years, until 2055.

The water phase was supplied by processed seawater, while the gas phase consisted of produced hydrocarbon gas from AJ_1 and AJ_5. The produced gas was routed through the separator and compressor before reinjection.

After the IAM-based base case had been established, IWAG injection was evaluated only within the IAM framework. Water and gas were injected in alternating cycles to support reservoir pressure and improve sweep efficiency while still honouring integrated operating constraints.

Sensitivity analyses were carried out to test the effect of injection rate and cycle duration on production performance. From these analyses, the W2G3 case with an 18-month cycle was identified as the best-performing IWAG configuration among the cases tested.

Performance Evaluation Metrics

Simulation performance was assessed using cumulative oil production, recovery factor, incremental oil recovery relative to the IAM base case, and VRR. These indicators were chosen to capture both the production gain and the operational stability of IWAG under IAM conditions.

FINDINGS AND DISCUSSION

Influence of IAM on the Base-Case Forecast

The reservoir-only and IAM base cases were compared over the same 30-year forecast period from 2025 to 2055, using identical reservoir descriptions, well locations, and completion intervals. The reservoir-only case produced 152.01 MMSTB compared with 127.65 MMSTB for IAM, corresponding to an approximately 19% higher cumulative production. Peak liquid rate decreased from 152.45 to 20.66 MSTB/day when the coupled well and surface network was included. This difference primarily reflects the influence of well hydraulics, network backpressure, pressure losses, and surface constraints on production deliverability rather than a difference in ultimate recoverable oil. The results are summarised in Table 2 and illustrated in Figure 3.

Table 2. Comparison of conventional and IAM base-case forecasts

Parameter	Conventional	IAM
Cumulative oil, MMSTB	152.01	127.65
Peak liquid rate, MSTB/day	152.45	20.66
Recovery factor, %	15	13
Remaining oil in place, MMSTB	859.93	884.29

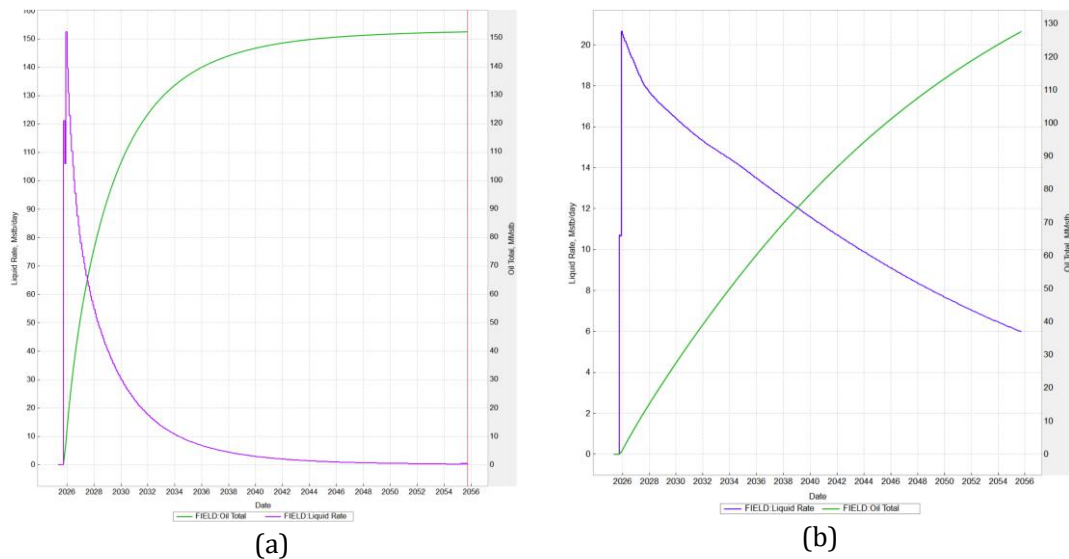


Figure 3. Base-case production response: (a) conventional reservoir simulation and (b) IAM simulation

Injection-Rate Sensitivity and Selection of W2G3

Injection-rate sensitivity was performed by varying water and gas rates while maintaining the same cycle duration for all cases. W1, W2, and W3 represent increasing water-rate levels, while G1, G2, and G3 represent increasing gas-rate levels. The tested rates were selected from the modelled injectivity range, with W3 representing the highest water-rate case evaluated. Gas-rate sensitivity was additionally constrained by the produced gas available for reinjection.

As shown in Table 3 and Figure 4, increasing the injected volume did not always produce an acceptable operating response. W3G gave the highest cumulative oil, 185.312 MMSTB, but reservoir pressure exceeded the initial pressure of 3,942.1 psi and a sharp water response indicated water breakthrough. W2G3 was therefore selected for further evaluation. It produced 160.496 MMSTB, corresponding to a recovery factor of 15.87% and an incremental 32.85 MMSTB relative to the IAM base case.

The same screening criteria were applied to all cases: cumulative oil, reservoir pressure, water response, and VRR. W2G3 provided a more controlled response than W3G, while its injection requirements remained within the modelled production and injection system.

Table 3. IWAG injection-rate sensitivity

Scenario	Water rate, bbl/day	Gas rate, MSCF/day	Cumulative oil, MMSTB
WG1	8,000	2,280	151.918
WG2	8,000	2,800	152.824
WG3	8,000	3,432	153.871
W2G	10,000	2,280	158.534
W3G	17,420	2,280	185.312
W2G3	10,000	3,432	160.496

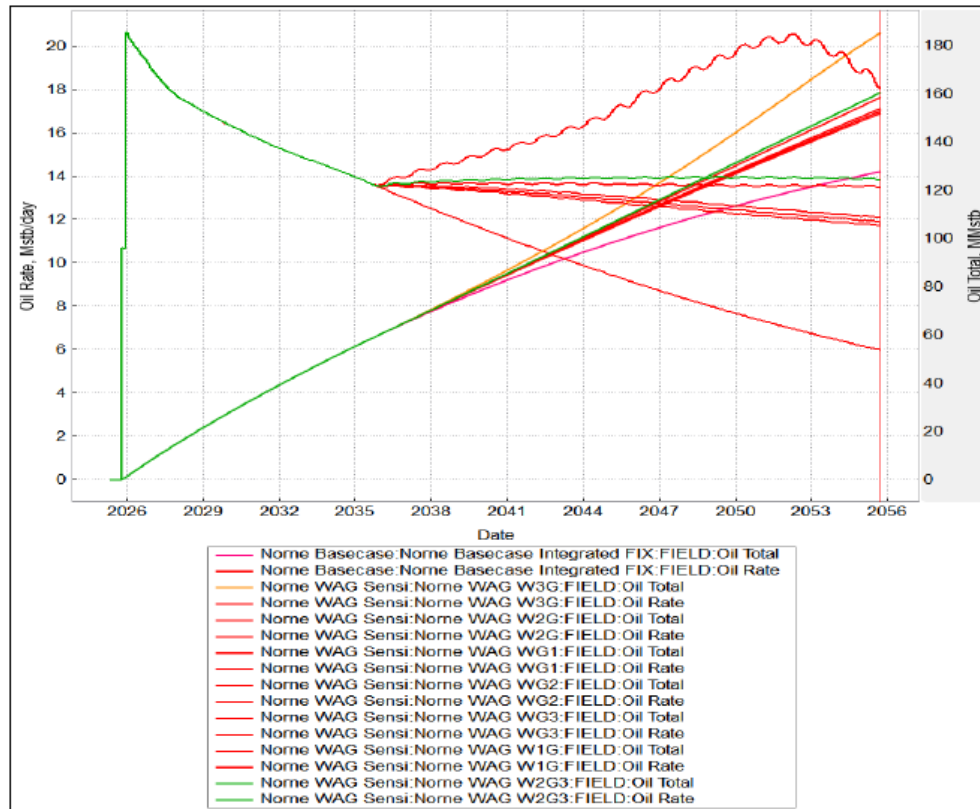


Figure 4. Production response for the IWAG injection-rate sensitivity cases
Cycle Duration, Incremental Recovery, and VRR

Cycle-duration sensitivity was then performed using W2G3. Cumulative oil increased from 160.003 MMSTB for the 1-month cycle to 162.179 MMSTB for the 18-month cycle. The difference between these cases was 2.176 MMSTB, or approximately 1.4%, indicating that the effect of cycle duration was relatively small within the range tested. The 18-month cycle was the best-performing configuration among those tested, producing 34.53 MMSTB of incremental oil relative to the IAM base case and increasing the recovery factor from approximately 13% to 16%. However, only cycles of 1, 6, 12, and 18 months were evaluated; therefore, a true optimum cannot be established and the response beyond 18 months remains uncertain.

Kong et al. (2021) reported an incremental recovery of 15.62% from immiscible nitrogen-WAG coreflooding under their best-tested condition, while Rostami et al. (2026) reported recovery improvements of approximately 13% in high-permeability cores and 5% in low-permeability cores under conditions approaching near-miscibility. These differences should be interpreted cautiously because the published studies were conducted at core scale, whereas the present study evaluates a field-scale reservoir model with coupled well and surface constraints.

The current scope was limited to evaluating cycles up to 18 months; therefore, it remains undetermined whether extending the cycle period would result in a continued production increase or if a plateau would be reached.

Table 4. Sensitivity of IWAG cycle duration

Cycle duration	Cumulative oil, MMSTB
1 month	160.003
6 months	160.496
12 months	161.034

Cycle duration	Cumulative oil, MMSTB
18 months	162.179

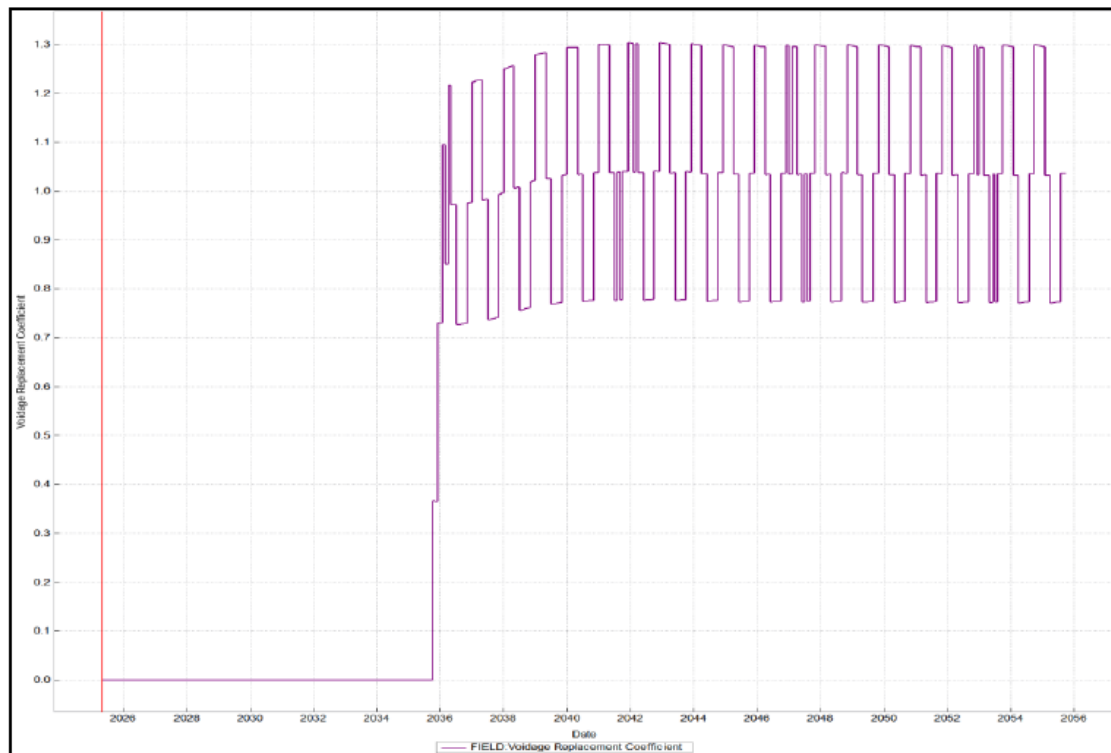


Figure 5. Voidage replacement ratio for the W2G3 injection case

The VRR in Figure 5 varies between approximately 0.7 and 1.3 during the IWAG period. Values below 1 indicate temporary under-replacement, while values above 1 indicate over-replacement. The cyclic variation is expected because water and gas are injected alternately. For operational screening, the main concern is whether VRR remains centred around unity without a sustained trend toward depletion or over-injection. W2G3 met this condition within the simulated

period.

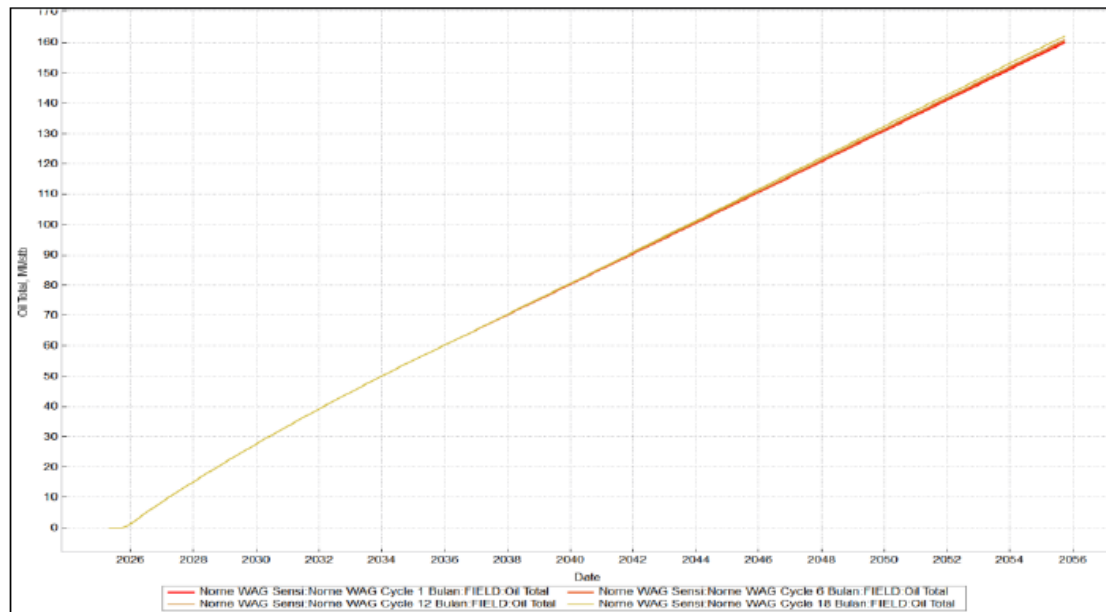


Figure 6. Cumulative oil response to IWAG cycle duration

The relatively small difference between the cycle cases also suggests that cycle duration should not be selected from cumulative oil alone. Pressure response, VRR, injection availability, and switching requirements should also be considered before a pilot design is finalized.

Streamline Response and Pilot-Project Implications

Streamline analysis was used to assess injector-producer communication and the distribution of injected fluids. In the selected IWAG case, streamlines from the four injectors extend towards the producing area through several reservoir sectors, indicating hydraulic communication between the injection and production wells. The variation in streamline density and direction also reflects the heterogeneous flow distribution within the reservoir.

Compared with the base case, the IWAG streamline pattern indicates broader reservoir contact around the injector-producer system. However, the streamline distribution alone does not provide a quantitative measure of sweep efficiency. Therefore, the observed pattern should be interpreted as qualitative evidence of improved reservoir contact rather than proof of uniform or complete sweep. Quantitative metrics such as swept pore volume or contacted pore volume would be required to confirm the magnitude of the sweep improvement.

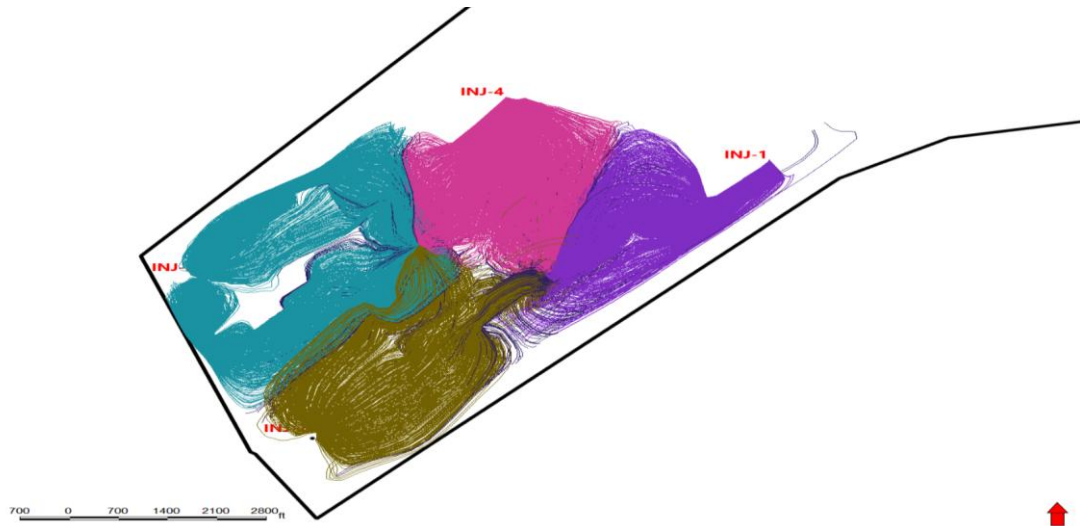


Figure 7. Streamline distribution for the selected IWAG scenario

Study Limitations

The results should be interpreted within several limitations of the modelling approach. The comparison between the reservoir-only and IAM cases is based on a fixed 30-year forecast period, so the approximately 19% difference in cumulative oil may partly reflect production timing rather than a difference in ultimate recoverable volume. The magnitude of this difference is also sensitive to how the conventional reservoir-only baseline is configured, particularly the well constraints applied in that case.

IAM results depend on the assumed well and surface-facility constraints, which were kept fixed and were not included in the sensitivity analysis. The study also did not evaluate the effect of three-phase relative-permeability hysteresis, although repeated drainage and imbibition during IWAG may influence gas trapping and fluid mobility. Cycle-duration sensitivity was limited to 1, 6, 12, and 18 months, so the 18-month case represents only the best-performing cycle among those tested rather than a true optimum.

The reservoir model represents a single deterministic realisation and was not history matched because no production history was available for the synthetic greenfield case. Geological uncertainty and probabilistic variations in reservoir properties were therefore not assessed. The IWAG forecast also assumes continuous availability of produced gas throughout the 20-year injection period without evaluating whether the required gas supply can be maintained operationally. For these reasons, the results are more appropriate for pilot screening and development planning than as a direct prediction of field performance.

CONCLUSION

Based on the results of the simulation and analysis, conclusions can be drawn as follows:

1. The reservoir-only case forecast 152.01 MMSTB, approximately 19% higher than the IAM forecast of 127.65 MMSTB at the same 30-year endpoint. This difference reflects the effect of coupled well and surface constraints and may partly be related to production timing, not ultimate recoverable oil.
2. W2G3 was the preferred injection-rate case, producing 160.496 MMSTB with a recovery factor of 15.87%, while avoiding the excessive water and pressure response observed in W3G. The 18-month cycle was the best-performing cycle among those tested, producing 162.179 MMSTB and increasing recovery factor to 16%

3. The VRR fluctuated between approximately 0.75 and 1.30 during the IWAG period. A VRR closer to 1 indicates a better balance between injected and produced reservoir volumes, which supports reservoir pressure maintenance.
4. The theoretical contribution is the evaluation of IWAG as a coupled reservoir-well-surface system. Practically, the difference between approximately 152 MSTB/day in the reservoir-only case and 21 MSTB/day in IAM shows the importance of facility constraints in production forecasting and facility sizing.
5. Future work should include economic evaluation, geological uncertainty analysis, alternative injection gases, three-phase hysteresis sensitivity, longer WAG cycles, and pilot surveillance to validate the modelled IWAG performance.

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